COPY

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

PETITION OF NORTHERN INDIANA PUBLIC SERVICE COMPANY ("NIPSCO") FOR (1) AUTHORITY TO MODIFY ITS RATES AND CHARGES FOR ELECTRIC UTILITY SERVICE; (2) APPROVAL OF NEW SCHEDULES OF RATES AND CHARGES APPLICABLE THERETO; (3) APPROVAL OF REVISED DEPRECIATION ACCRUAL RATES; (4) INCLUSION IN ITS BASIC RATES AND CHARGES OF THE COSTS ASSOCIATED WITH CERTAIN PREVIOUSLY APPROVED QUALIFIED POLLUTION CONTROL PROPERTY PROJECTS; (5) AUTHORITY TO IMPLEMENT A RATE ADJUSTMENT MECHANISM PURSUANT TO IND. CODE § 8-1-2-42(a) TO (A) TIMELY RECOVER CHARGES AND CREDITS FROM REGIONAL TRANSMISSION ORGANIZATIONS AND NIPSCO'S TRANSMISSION REVENUE REQUIREMENTS; (B) TIMELY RECOVER NIPSCO'S PURCHASED POWER COSTS; AND (C) ALLOCATE NIPSCO'S OFF SYSTEM SALES REVENUES; (6) APPROVAL OF VARIOUS CHANGES TO NIPSCO'S ELECTRIC SERVICE TARIFF INCLUDING WITH RESPECT TO THE GENERAL RULES AND REGULATIONS, THE ENVIRONMENTAL COST RECOVERY MECHANISM AND THE ENVIRONMENTAL EXPENSE MECHANISM; (7) APPROVAL OF THE CLASSIFICATION OF NIPSCO'S FACILITIES AS TRANSMISSION OR DISTRIBUTION IN ACCORDANCE WITH THE FEDERAL ENERGY REGULATORY COMMISSION'S SEVEN-FACTOR TEST; AND (8) APPROVAL OF AN ALTERNATIVE REGULATORY PLAN PURSUANT TO IND. CODE § 8-1-2.5-1 *ET SEQ.* TO THE EXTENT SUCH RELIEF IS NECESSARY TO EFFECT THE RATEMAKING MECHANISMS PROPOSED BY NIPSCO.

CAUSE NO. 43526

FILED
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INDIANA UTILITY
REGULATORY COMMISSION

NORTHERN INDIANA PUBLIC SERVICE COMPANY'S FIRST SET OF CORRECTIONS <u>TO CASE-IN-CHIEF</u>

Pursuant to Paragraph 15 of the Prehearing Conference Order in this Cause, Petitioner Northern Indiana Public Service Company ("NIPSCO") submits the following corrections to the direct testimony and exhibits of the following witnesses contained in its case-in-chief filed with the Commission on August 29, 2008:

1. Linda E. Miller Testimony (Volume 1). Attachment 1 contains a clean and black-lined copy of the corrected pages to Petitioner's Exhibit LEM-1.

2. Linda E. Miller Exhibit (Volume 1). Attachment 2 contains a clean copy of the corrected pages to Petitioner's Exhibit LEM-2, Petitioner's Exhibit LEM-3 and Petitioner's Exhibit LEM-4 A black-lined copy is not available for the following corrections:

(a) Petitioner's Exhibit LEM-2, Page 3 of 4, CORRECTED September 24, 2008: Line 20 has been revised to reference the correct line numbers.

(b) Petitioner's Exhibit LEM-2, Page 4 of 4, CORRECTED September 24, 2008: Line 5 has been revised to remove the word "/ Credit".

(c) Petitioner's Exhibit LEM-3, Adjustment REV-4, CORRECTED September 24, 2008: The language describing the pro forma adjustment has been revised.

(d) Petitioner's Exhibit LEM-3, Adjustment REV-5, CORRECTED September 24, 2008: The language describing the pro forma adjustment has been revised.

(e) Petitioner's Exhibit LEM-3, Adjustment REV-6, CORRECTED September 24, 2008: The language describing the pro forma adjustment has been revised.

(f) Petitioner's Exhibit LEM-3, Adjustment FP-1, CORRECTED September 24, 2008: The dollar sign has been deleted from line 1 and a dollar sign has been added to line 2.

(g) Petitioner's Exhibit LEM-3, Adjustment FP-2, CORRECTED September 24, 2008: The language describing the pro forma adjustment has been revised.

(h) Petitioner's Exhibit LEM-3, Adjustment OM-11, CORRECTED September 24, 2008: The description on line 2 has been revised to more accurately describe the positive component of the adjustment.

(i) Petitioner's Exhibit LEM-3, Adjustment OM-12, CORRECTED September 24, 2008: The language describing the pro forma adjustment has been revised.

(j) Petitioner's Exhibit LEM-3, Adjustment OM-13, CORRECTED September 24, 2008: The language describing the pro forma adjustment has been revised.

(k) Petitioner's Exhibit LEM-4, Page 2 of 2, CORRECTED September 24, 2008: Line 3 and Line 6 have been revised to delete the phrase "(includes Phase 1&2)".

3. Phillip W. Pack Exhibit (Volume 2). Attachment 3 contains a clean and black-lined copy of the corrected pages to Petitioner's Exhibit PWP-2.

4. Robert D. Greneman Exhibit (Volume 3). Attachment 4 contains a clean copy of the corrected pages to Petitioner's Exhibit RDG-3. A black-lined copy is not available for the following corrections:

(a) Schedule 2.2, Page 1 of 2 CORRECTED September 24, 2008 and Schedule 2.2, Page 2 of 2 CORRECTED September 24, 2008 were changed to correct for a $35,600 cross-foot error in Dusk-to-Dawn lighting. The cost of service study workpapers already incorporate this correction.

(b) Schedule 3.0, Page 2 of 2 CORRECTED September 24, 2008 was corrected to reflect a single composite Step One rate of return applicable to each of the three lighting classes. The logical switch in Excel was not invoked just prior to printing this particular schedule. The corrections do not change rate design for the lighting classes.

(c) Schedule 3.1, Page 1 of 2 CORRECTED September 24, 2008 and Schedule 3.1, Page 2 of 2 CORRECTED September 24, 2008 were corrected for the above and for a $46,879 cross-foot error in Dusk-to-Dawn lighting. The cost of service study workpapers already incorporate these corrections.

(d) Schedule 3.2, Page 2 of 2 CORRECTED September 24, 2008: Schedule 3.2 was corrected for the same corrections made to Schedule 3.1.

For the convenience of the Commission and the parties, a set of the corrected pages to Petitioner's Exhibit RDG-3 is included showing the amounts that were changed in **bold** font.

5. Curt A. Westerhausen Testimony (Volume 3). Attachment 5 contains a clean and black-lined copy of a corrected page to Petitioner's Exhibit CAW-1.

6. Curt A. Westerhausen Exhibit (Volume 3). Attachment 6 contains a clean and black-lined copy of the corrected pages to Petitioner's Exhibit CAW-2.

Respectfully Submitted,

Daniel W. McGill

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Attorneys for Petitioner NORTHERN INDIANA PUBLIC SERVICE COMPANY

CERTIFICATE OF SERVICE

The undersigned hereby certifies that a copy of Northern Indiana Public Service Company's First Set of Corrections has been served upon the following by depositing copies thereof in the United States Mail, first class postage prepaid, addressed to:

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this 29th day of September, 2008.

Daniel W. McGill
Daniel W. McGill

INDS01 DWM 1068751v2

Attachment 1

electric average expense is $1,122,491. The 2007 actual was a credit of $8,844,269 and the amount allocated to electric was a credit of $6,115,812. After deducting for the portion capitalized, the 2007 actual electric expense was a credit of $4,640,067. The 5-year average electric expense of $1,122,491 as compared to the 2007 electric credit of $4,640,067 results in a required increase (debit) adjustment of $5,762,558. NIPSCO Witness Robert D. Campbell further discusses the company's pension plans. If this adjustment is not included, test year operating expenses would be understated.

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NIPSCO's Indianapolis office, as a result of additional new employees and the relocation of an employee from Merrillville. This adjustment was calculated by obtaining the new annual lease amount, deducting for space occupied by the NIPSCO lobbyist because those charges are non-recoverable, and allocating to electric. If this adjustment is not included, test year operating expenses would be understated.

Q46. Please explain Adjustment OM-22 on <u>Petitioner's Exhibit LEM-2</u>.

A46. Adjustment OM-22 on <u>Petitioner's Exhibit LEM-2</u> is to increase (debit) test year operating expenses in the amount of $2,067,189 to reflect increased electric property insurance costs. This adjustment is based on new insurance premiums effective July, 2008. The premium increases are a result of increased electric generation property values as used by insurance underwriters for premium determinations. If this adjustment is not included, test year operating expenses would be understated.

C. <u>Depreciation and Amortization Adjustments</u>

Q47. Please explain Adjustment DA-1 on <u>Petitioner's Exhibit LEM-2</u>.

A47. Adjustment DA-1 on <u>Petitioner's Exhibit LEM-2</u> is to increase (debit) test year operating expenses in the amount of $227,322 to reflect the change in common allocation methodology implemented in the second quarter of the test year. As mentioned above, Mr. Hershberger discusses this change in methodology. If this adjustment is not included, test year operating expenses would be understated.

Public Utility Fees, and (e) uncollectible accounts. The resulting proposed increase in revenue requirement is $23,983,452.

Q62. Please explain Adjustment PF-2 on <u>Petitioner's Exhibit LEM-2</u>.

A62. Adjustment PF-2 on <u>Petitioner's Exhibit LEM-2</u> reflects the additional uncollectible accounts expense on the revenue increase by multiplying the proposed increase in revenue requirement by the multiplier of 0.226593%, for an increase in expense of $54,345 at the proposed rates level.

Q63. Please explain Adjustment PF-3 on <u>Petitioner's Exhibit LEM-2</u>.

A63. Adjustment PF-3 on <u>Petitioner's Exhibit LEM-2</u> is a calculation of the URT applicable to the proposed increase in revenue requirement and is calculated by applying the 1.4% rate to the proposed increase of $23,983,452, resulting in an increase of $335,768.

Q64. Please explain Adjustment PF-4 on <u>Petitioner's Exhibit LEM-2</u>.

A64. Adjustment PF-4 on <u>Petitioner's Exhibit LEM-2</u> is a calculation of the Public Utility Fees applicable to the proposed increase in revenue requirement and is calculated by applying the 0.1204% rate to the proposed increase of $23,983,452, resulting in an increase of $28,876.

Q65. Please explain Adjustment PF-5 on <u>Petitioner's Exhibit LEM-2</u>.

A65. Adjustment PF-5 on <u>Petitioner's Exhibit LEM-2</u> is to account for income taxes applicable to the proposed increase in net operating income. It is calculated by applying the Federal income tax rate to the pro forma federal taxable income and the Indiana state income tax rate to the pro forma state taxable income, resulting in an increase of $9,568,050. As Mr.

O'Brien explains, federal and state taxable incomes are not the same due to different deductions.

Q66. Please explain Petitioner's Exhibit LEM-3.

A66. Petitioner's Exhibit LEM-3 consists of a separate page for each income statement adjustment. The individual pages present additional detail where needed to further explain the amounts included in Petitioner's Exhibit LEM-2 and discussed individually in my testimony. Where appropriate, the workpapers to be filed in this proceeding provide further detail.

V. NET ORIGINAL COST RATE BASE

Q67. Please explain Petitioner's Exhibit LEM-4.

A67. Petitioner's Exhibit LEM-4, page 1 of 2, quantifies NIPSCO's net original cost rate base as of December 31, 2007, including updates, which I describe later in my testimony. Column B shows the actual rate base as of December 31, 2007, per NIPSCO's books. Column C shows the debit and credit updates to rate base by line item. Column D shows the total net original cost rate base with the rate base updates reflected. Petitioner's Exhibit LEM-4, page 2 of 2, shows the detail of the rate base updates, which is further discussed below.

Q68. Please explain Update RB-1 on Petitioner's Exhibit LEM-4, page 2 of 2.

A68. Update RB-1 on Petitioner's Exhibit LEM-4, page 2 of 2, decreases (credits) utility plant in service in the amount of $175,909,015 to reflect the removal of units at Mitchell,

$14,599,077 of distribution assets being re-classified as transmission assets. This update has no impact on total plant in service values. In addition, the accumulated deprecation and amortization reserves were adjusted. These updates are identified as RB-5 and RB-6. In addition, the Company made updates to rate base to reflect the impact of an error made in performing certain plant retirements and made other adjusting entries to correct assets that had been misclassified as to specific plant account. These updates are identified as RB-7 through RB-10. Mr. Hershberger further discusses these adjustments.

Q73. Please discuss the Deferred Charges shown on <u>Petitioner's Exhibit LEM-4</u>, page 1 of 2.

A73. The deferred charges shown on <u>Petitioner's Exhibit LEM-4</u>, page 1 of 2, relate to the unamortized balance at December 31, 2007 of deferred charges in connection with the (1) Pure Air flue gas desulfurization ("FGD") at the Bailly Generating Station, (2) R. M. Schahfer Generating Station Units 17 and 18, and (3) prepaid pension asset.

Q74. Please explain the Pure Air Deferred Charges on <u>Petitioner's Exhibit LEM-4</u>, page 1 of 2.

A74. The Pure Air Deferred Charges on <u>Petitioner's Exhibit LEM-4</u>, page 1 of 2, in the amount of $526,218 represent the remaining unamortized balance of the regulatory asset established in Cause No. 43188. This asset will be fully amortized by year-end 2008.

Q75. Please explain the Unit 17 Depreciation on <u>Petitioner's Exhibit LEM-4</u>, page 1 of 2.

A75. The Unit 17 Depreciation on <u>Petitioner's Exhibit LEM-4</u>, page 1 of 2, in the amount of $542,928 relates to the deferral of depreciation on Schahfer Unit 17 after it went into

Creek Facility is reflected in NIPSCO's rates. NIPSCO has proposed that, if such deferral authority is granted, the Step Two Adjustment include an amortization of the deferred amounts as an above-the-line expense and inclusion of the unamortized amount in NIPSCO's rate base. The Step Two Adjustment will also include a return on NIPSCO's investment in the Sugar Creek Facility. Mr. Shambo addresses the policy and structure of the Step Two Adjustment.

Q95. Please summarize your testimony for the Step Two Adjustment.

A95. NIPSCO requires a net increase in base rate revenues of $80,723,642 in the Step Two Adjustment to recover the revenue requirement associated with the Sugar Creek Facility. This amount is calculated to provide the opportunity to earn additional net operating income of $30,619,764. Support for the Step Two Adjustment is presented in Petitioner's Exhibits LEM-6 through LEM-9.

Q96. Please describe the exhibits relating to Step Two.

A96. Petitioner's Exhibit LEM-6, page 1 of 2, is a statement of Sugar Creek net operating income for the test year ended December 31, 2007 on a pro forma basis and adjusted for the proposed revenue increase of $80,723,642. Petitioner's Exhibit LEM-6, page 2 of 2, shows the calculation of the proposed Sugar Creek revenue increase. Petitioner's Exhibit LEM-7 consists of a separate page for each Sugar Creek income statement adjustment. Petitioner's Exhibit LEM-8, page 1 of 2, shows the Sugar Creek original cost rate base and a summary of the proposed updates. Petitioner's Exhibit LEM-8, page 2 of 2, shows the detail of the proposed updates.

issuance and dates of maturity, respectively. The principal amount outstanding is shown in Column E. Column F reflects the interest requirement, which is the principal amount (Column E) multiplied times the interest rate (Column A). Column G reflects the overall cost of debt, which flows to page 1 of 3.

Q97. Please explain Adjustment SCOM-1 on <u>Petitioner's Exhibit LEM-6</u>, page 1 of 2.

A97. Adjustment SCOM-1 on <u>Petitioner's Exhibit LEM-6</u>, page 1 of 2, is the increase (debit) to operating expenses in the amount of $3,572,954 for the variable production expense required to operate the Sugar Creek Facility. Mr. Pack further describes the calculation of this adjustment.

Q98. Please explain Adjustment SCOM-2 on <u>Petitioner's Exhibit LEM-6</u>, page 1 of 2.

A98. Adjustment SCOM-2 on <u>Petitioner's Exhibit LEM-6</u>, page 1 of 2, is the increase (debit) to operating expenses in the amount of $5,815,467 for other O&M expenses, which consists of fixed operating expenses for the plant as well as property insurance related to the Sugar Creek Facility. Mr. Pack further describes the calculation of this adjustment.

Q99. Please explain Adjustment SCDA-1 on <u>Petitioner's Exhibit LEM-6</u>, page 1 of 2.

A99. Adjustment SCDA-1 on <u>Petitioner's Exhibit LEM-6</u>, page 1 of 2, is the increase (debit) to electric operating expenses for $11,236,857 for the annual depreciation/amortization expense of the Sugar Creek Facility. This adjustment is based on the depreciation study performed by NIPSCO Witness John Spanos.

amounts should not be included in utility plant in service. Further adjustment may be required because the purchase agreement requires a true-up for working capital. As soon as the information is available, Petitioner will true-up the final purchase price, including the filing of amended exhibits, to appropriately reflect the correct amount for purposes of the rate base updates. This true-up will likely change the materials and supplies inventory balance, which is described in Update SCRB-2.

Q103. Why are you using a 6.5% rate to calculate carrying charges and using a five year amortization period?

A103. That rate is consistent with the terms of the FAC71 Settlement as is the five year amortization period.

Q104. Please explain Adjustment SCOTX-1 on Petitioner's Exhibit LEM-6, page 1 of 2.

A104. Adjustment SCOTX-1 on Petitioner's Exhibit LEM-6, page 1 of 2, is the increase (debit) to property taxes for $1,132,243 for the Sugar Creek Facility. This amount was provided by Mr. O'Brien, who discusses it further. If this adjustment is not made, property tax expense will be understated.

Q105. Please explain Adjustment SCPF-1 on Petitioner's Exhibit LEM-6, page 1 of 2.

A105. Adjustment SCPF-1 on Petitioner's Exhibit LEM-6, page 1 of 2, shows the calculation of the increased revenue requirement for NIPSCO necessary to provide an 8.43% return on net original cost rate base of $363,223,758. The increased revenue requirement is calculated by determining the requested increase in operating income. The requested operating income increase is determined by applying the proposed rate of return of 8.43%

to the net original cost rate base for Sugar Creek shown on page 2 of 2 of Petitioner's Exhibit LEM-6. The increase in operating income is then grossed up for the following taxes and fees: (a) Federal income taxes, (b) State income taxes, (c) URT, (d) Public Utility Fees, and (e) Uncollectible accounts. The proposed increase in revenue requirement is $80,723,642.

Q106. Please explain Adjustment SCOM-3 on Petitioner's Exhibit LEM-6, page 1 of 2.

A106. Adjustment SCOM-3 on Petitioner's Exhibit LEM-6, page 1 of 2, reflects the additional uncollectible accounts expense on the revenue increase by multiplying the proposed increase in revenue requirement by the multiplier of 0.226593%, for an increase in expense of $182,914 at the proposed rates level.

Q107. Please explain Adjustment SCOTX-2 on Petitioner's Exhibit LEM-6, page 1 of 2.

A107. Adjustment SCOTX-2 on Petitioner's Exhibit LEM-6, page 1 of 2, is a calculation of the Public Utility Fees applicable to the proposed increase in revenue requirement and is calculated by applying the 0.1204% rate to the proposed increase of $80,723,642, resulting in an increase of $97,191.

Q108. Please explain Adjustment SCOTX-3 on Petitioner's Exhibit LEM-6, page 1 of 2.

A108. Adjustment SCOTX-3 on Petitioner's Exhibit LEM-6, page 1 of 2, is a calculation of the URT applicable to the proposed increase in revenue requirement and is calculated by applying the 1.4% rate to the proposed increase of $80,723,642, resulting in an increase of $1,130,131.

electric average expense is $1,122,491. The 2007 actual was a credit of $8,844,269 and the amount allocated to electric was a credit of $6,115,812. After deducting for the portion capitalized, the 2007 actual electric expense was a credit of $4,640,067. The 5-year average electric expense of $1,122,491 as compared to the 2007 electric credit of $4,640,067 results in a required increase (debit) adjustment of $5,762,558. NIPSCO Witness Robert D. Campbell further discusses the company's pension plans. If this adjustment is not included, test year operating expenses would be understated.

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A67. Petitioner's Exhibit LEM-4, page 1 of 2, quantifies NIPSCO's net original cost rate base as of December 31, 2007, including updates, which I describe later in my testimony. Column B shows the actual rate base as of December 31, 2007, per NIPSCO's books. Column C shows the debit and credit updates to rate base by line item. Column D shows the total net original cost rate base with the rate base updates reflected. Petitioner's Exhibit LEM-4, page 2 of 2, shows the detail of the rate base updates, which is further discussed below.

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Q68. Please explain Update RB-1 on Petitioner's Exhibit LEM-4, page 2 of 2.

A68. Update RB-1 on Petitioner's Exhibit LEM-4, page 2 of 2, decreases (credits) utility plant in service in the amount of $175,909,015 to reflect the removal of units at Mitchell,

$14,599,077 of distribution assets being re-classified as transmission assets. This update has no impact on total plant in service values. In addition, the accumulated deprecation and amortization reserves were adjusted. These updates are identified as RB-5 and RB-6. In addition, the Company made updates to rate base to reflect the impact of an error made in performing certain plant retirements and made other adjusting entries to correct assets that had been misclassified as to specific plant account. These updates are identified as RB-7 through RB-10. Mr. Hershberger further discusses these adjustments.

Q73. Please discuss the Deferred Charges shown on Petitioner's Exhibit LEM-4, page 1 of 2.

A73. The deferred charges shown on Petitioner's Exhibit LEM-4, page 1 of 2, relate to the unamortized balance at December 31, 2007 of deferred charges in connection with the (1) Pure Air flue gas desulfurization ("FGD") at the Bailly Generating Station, (2) R. M. Schahfer Generating Station Units 17 and 18, and (3) prepaid pension asset.

Q74. Please explain the Pure Air Deferred Charges on Petitioner's Exhibit LEM-4, page 1 of 2.

A74. The Pure Air Deferred Charges on Petitioner's Exhibit LEM-4, page 1 of 2, in the amount of $526,218 represent the remaining unamortized balance of the regulatory asset established in Cause No. 43188. This asset will be fully amortized by year-end 2008.

Q75. Please explain the Unit 17 Depreciation on Petitioner's Exhibit LEM-4, page 1 of 2.

A75. The Unit 17 Depreciation on Petitioner's Exhibit LEM-4, page 1 of 2, in the amount of $542,928 relates to the deferral of depreciation on Schahfer Unit 17 after it went into

Creek Facility is reflected in NIPSCO's rates. NIPSCO has proposed that, if such deferral authority is granted, the Step Two Adjustment include an amortization of the deferred amounts as an above-the-line expense and inclusion of the unamortized amount in NIPSCO's rate base. The Step Two Adjustment will also include a return on NIPSCO's investment in the Sugar Creek Facility. Mr. Shambo addresses the policy and structure of the Step Two Adjustment.

Q95. Please summarize your testimony for the Step Two Adjustment.

A95. NIPSCO requires a net increase in base rate revenues of $80,723,642 in the Step Two Adjustment to recover the revenue requirement associated with the Sugar Creek Facility. This amount is calculated to provide the opportunity to earn additional net operating income of $30,619,764. Support for the Step Two Adjustment is presented in Petitioner's Exhibits LEM-6 through LEM-9.

Q96. Please describe the exhibits relating to Step Two.

A96. Petitioner's Exhibit LEM-6, page 1 of 2, is a statement of Sugar Creek net operating income for the test year ended December 31, 2007 on a pro forma basis and adjusted for the proposed revenue increase of $80,723,642. Petitioner's Exhibit LEM-6, page 2 of 2, shows the calculation of the proposed Sugar Creek revenue increase. Petitioner's Exhibit LEM-7 consists of a separate page for each Sugar Creek income statement adjustment. Petitioner's Exhibit LEM-8, page 1 of 2, shows the Sugar Creek original cost rate base and a summary of the proposed updates. Petitioner's Exhibit LEM-8, page 2 of 2, shows the detail of the proposed updates.

Deleted: and rate base and capital structure update issuance and dates of maturity, respectively. The principal amount outstanding is shown in Column E. Column F reflects the interest requirement, which is the principal amount (Column E) multiplied times the interest rate (Column A). Column G reflects the overall cost of debt, which flows to page 1 of 3.

Q97. Please explain Adjustment SCOM-1 on Petitioner's Exhibit LEM-6, page 1 of 2.

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A97. Adjustment SCOM-1 on Petitioner's Exhibit LEM-6, page 1 of 2, is the increase (debit) to operating expenses in the amount of $3,572,954 for the variable production expense required to operate the Sugar Creek Facility. Mr. Pack further describes the calculation of this adjustment.

Q98. Please explain Adjustment SCOM-2 on Petitioner's Exhibit LEM-6, page 1 of 2.

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A98. Adjustment SCOM-2 on Petitioner's Exhibit LEM-6, page 1 of 2, is the increase (debit) to operating expenses in the amount of $5,815,467 for other O&M expenses, which consists of fixed operating expenses for the plant as well as property insurance related to the Sugar Creek Facility. Mr. Pack further describes the calculation of this adjustment.

Q99. Please explain Adjustment SCDA-1 on Petitioner's Exhibit LEM-6, page 1 of 2.

A99. Adjustment SCDA-1 on Petitioner's Exhibit LEM-6, page 1 of 2, is the increase (debit) to electric operating expenses for $11,236,857 for the annual depreciation/amortization expense of the Sugar Creek Facility. This adjustment is based on the depreciation study performed by NIPSCO Witness John Spanos.

amounts should not be included in utility plant in service. Further adjustment may be required because the purchase agreement requires a true-up for working capital. As soon as the information is available, Petitioner will true-up the final purchase price, including the filing of amended exhibits, to appropriately reflect the correct amount for purposes of the rate base updates. This true-up will likely change the materials and supplies inventory balance, which is described in Update SCRB-2.

Q103. Why are you using a 6.5% rate to calculate carrying charges and using a five year amortization period?

A103. That rate is consistent with the terms of the FAC71 Settlement <u>as is the five year amortization period</u>.

Q104. Please explain Adjustment SCOTX-1 on <u>Petitioner's Exhibit LEM-6</u>, page 1 of 2.

A104. Adjustment SCOTX-1 on <u>Petitioner's Exhibit LEM-6</u>, page 1 of 2, is the increase (debit) to property taxes for $1,132,243 for the Sugar Creek Facility. This amount was provided by Mr. O'Brien, who discusses it further. If this adjustment is not made, property tax expense will be understated.

Q105. Please explain Adjustment SCPF-1 on <u>Petitioner's Exhibit LEM-6</u>, page 1 of 2.

A105. Adjustment SCPF-1 on <u>Petitioner's Exhibit LEM-6</u>, page 1 of 2, shows the calculation of the increased revenue requirement for NIPSCO necessary to provide an 8.43% return on net original cost rate base of $363,223,758. The increased revenue requirement is calculated by determining the requested increase in operating income. The requested operating income increase is determined by applying the proposed rate of return of 8.43%

to the net original cost rate base for Sugar Creek shown on page 2 of 2 of Petitioner's Exhibit LEM-6. The increase in operating income is then grossed up for the following taxes and fees: (a) Federal income taxes, (b) State income taxes, (c) URT, (d) Public Utility Fees, and (e) Uncollectible accounts. The proposed increase in revenue requirement is $80,723,642.

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Q106. Please explain Adjustment SCOM-3 on Petitioner's Exhibit LEM-6, page 1 of 2.

A106. Adjustment SCOM-3 on Petitioner's Exhibit LEM-6, page 1 of 2, reflects the additional uncollectible accounts expense on the revenue increase by multiplying the proposed increase in revenue requirement by the multiplier of 0.226593%, for an increase in expense of $182,914 at the proposed rates level.

Q107. Please explain Adjustment SCOTX-2 on Petitioner's Exhibit LEM-6, page 1 of 2.

A107. Adjustment SCOTX-2 on Petitioner's Exhibit LEM-6, page 1 of 2, is a calculation of the Public Utility Fees applicable to the proposed increase in revenue requirement and is calculated by applying the 0.1204% rate to the proposed increase of $80,723,642, resulting in an increase of $97,191.

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Q108. Please explain Adjustment SCOTX-3 on Petitioner's Exhibit LEM-6, page 1 of 2.

A108. Adjustment SCOTX-3 on Petitioner's Exhibit LEM-6, page 1 of 2, is a calculation of the URT applicable to the proposed increase in revenue requirement and is calculated by applying the 1.4% rate to the proposed increase of $80,723,642, resulting in an increase of $1,130,131.

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Attachment 2

Northern Indiana Public Service Company
Calculation of Proposed Revenue Increase
Based on Pro Forma Operating Results
Original Cost Rate Base Estimated at December 31, 2007

Line No.	Description					Revenue Deficiency
1	Net Original Cost Rate Base					$ 2,341,480,136
2	Rate of Return					8.34%
3	Required Net Operating Income					195,279,443
4	Pro Forma Net Operating Income					181,283,030
5	Increase in Net Operating Income (NOI Shortfall)					13,996,413
6	Effective Incremental RevenueINOI Conversion Factor					58.36%
7	Increase in Revenue Requirement (Based on Net Original Cost Rate Base) (Line 5 / Line 6)					$ 23,983,452
8	One		1.000000			
9	Less: Public Utility Fee		0.001204			
10	Less: Bad Debt		0.002266			
11	One Less PUF, IURT, Bad Debt			0.996530		
12	One	1.000000				
13	Less: Public Utility Fee	0.014000				
14	Taxable Adjusted Gross Income Tax		0.996530			
15	Adjusted Gross Income Tax Rate		0.085000			
16	Adjusted Gross Income Tax			0.084705		
17	Indiana Apportionment		0.996530			
18	Indiana State Income Tax Rate		0.085000			
19	Effective Indiana Income Tax Rate			0.084705		
20	Line 11 less line 13 less line 19				0.897825	
21	One			1.000000		
22	Less: Federal Income Tax Rate			0.350000		
23	One Less Federal Income Tax Rate				0.650000	
24	Effective Incremental Revenue / NOI Conversion Factor					58.36%

Northern Indiana Public Service Company
Requested Revenue Increase Reconciliation
For the Twelve Month Period Ended December 31, 2007

Line No.	Description	Margin at Present Rates	Adjustment to Base Rates	Margin at Proposed Rates
	A	B	C	D
1	Base Revenue (less cost of fuel)	$ 836,907,692	$ 23,983,452	$ 860,891,144
2	Add: ECRM	$ -	$ 25,627,423	$ 25,627,423
3	Add: EERM	$ -	$ 14,113,249	$ 14,113,249
4	Adjusted Base Revenue (less cost of fuel)	$ 836,907,692	$ 63,724,124	$ 900,631,816
5	Riders / Trackers:			
6	ECRM	$ 25,627,423	$ (25,627,423)	$ -
7	EERM	$ 14,113,249	$ (14,113,249)	$ -
8	Proposed:			
9	Total Riders/Trackers	$ 39,740,672	$ 39,740,672	$ -
10	Total Margin	$ 876,648,364	$ 23,983,452	$ 900,631,816
11	Net Increase/(Decrease) in Base Rate Revenue		$ 23,983,452	
12	Total Margin	$ 876,648,364	$ 23,983,452	$ 900,631,816
13	Net Customer Bill Impacts, Net Increase (Decrease)		$ 23,983,452	

Petitioner's Exhibit No. LEM - 3
Cause No. 43526
Adjustment REV - 4
CORRECTED
September 24, 2008

Northern Indiana Public Service Company
Pro Forma Adjustment to Operating Revenue
Twelve Months Ended December 31, 2007

This pro forma adjustment increased 2007 test year revenue to reflect the removal of the reserve amount recorded in accordance with the settlement agreement in FAC 71.

Line No.	Description	Amount
	A	B
1	Increase in Pro Forma Test Year Revenue	$ 33,500,000

Petitioner's Exhibit No. LEM - 3
Cause No. 43526
Adjustment REV - 5
CORRECTED
September 24, 2008

Northern Indiana Public Service Company
Pro Forma Adjustment to Operating Revenue
Twelve Months Ended December 31, 2007

This pro forma adjustment decreased 2007 test year revenue to reflect the amount related to the reversal of a reserve related to financial transactions.

Line No.	Description	Amount
	A	B
1	Decrease in Pro Forma Test Year Revenue	$ (2,203,737)

Petitioner's Exhibit No. LEM - 3
Cause No. 43526
Adjustment REV - 6
CORRECTED
September 24, 2008

Northern Indiana Public Service Company
Pro Forma Adjustment to Operating Revenue
Twelve Months Ended December 31, 2007

This pro forma adjustment decreased 2007 test year revenue related to Rate 825 Metal Melters.

Line No.	Description	Amount
	A	B
1	Decrease In Pro Forma Test Year Revenue	$ (804,136)

Petitioner's Exhibit No. LEM - 3
Cause No. 43526
Adjustment FP - 1
CORRECTED
September 24, 2008

Northern Indiana Public Service Company
Pro Forma Adjustment to Fuel and Purchased Power
Twelve Months Ended December 31, 2007

This pro forma adjustment decreased 2007 test year fuel by the amount related to the pro forma revenue adjustment for normal weather.

Line No.	Description	Amount
	A	B
1	2007 Weather Normalization KWH	(163,302,530)
2	Base Cost of Fuel	0.022556
3	**Decrease in Pro Forma Test Year Fuel**	$ (3,683,450)

Petitioner's Exhibit No. LEM -3
Cause No. 43526
Adjustment FP - 2
CORRECTED
September 24, 2008

Northern Indiana Public Service Company
Pro Forma Adjustment to Fuel and Purchased Power
Twelve Months Ended December 31, 2007

This pro forma adjustment decreased 2007 test year fuel related to the pro forma revenue adjustment for Rate 825 Metal Melters.

Line No.	Description	Amount
	A	B
1	Decrease In Pro Forma Test Year Fuel	$ (628,813)

Petitioner's Exhibit No. LEM - 3
Cause No. 43526
Adjustment OM - 11
CORRECTED
September 24, 2008

Northern Indiana Public Service Company
Pro Forma Adjustment to Operation and Maintenance Expense
Twelve Months Ended December 31, 2007

This pro forma adjustment decreased 2007 test year O&M expense to eliminate the Edison Electric Institute (EEI) dues related to lobbying.

Line No.	Description	Amount
	A	B
1	Adjustment to remove lobbying activities from 2007 invoice	$ (128,013)
2	Adjustment of the net difference between the 2006 accrual and actual payment made in 2007	$ 72,588
3	**Decrease in Pro Forma Test Year O&M Expense**	**$ (55,425)**

Petitioner's Exhibit No. LEM - 3
Cause No. 43526
Adjustment OM - 12
CORRECTED
September 24, 2008

Northern Indiana Public Service Company
Pro Forma Adjustment to Operation and Maintenance Expense
Twelve Months Ended December 31, 2007

This pro forma adjustment decreased 2007 test year O&M expense to eliminate general and goodwill advertising costs.

Line No.	Description	Amount
	A	B
1	2007 General Advertising	$ 59,692
2	1Q Common Allocation Adjustment	$ 371
3	**Decrease in Pro Forma Test Year O&M Expense**	**$ (60,063)**

Petitioner's Exhibit No. LEM - 3
Cause No. 43526
Adjustment OM - 13
CORRECTED
September 24, 2008

Northern Indiana Public Service Company
Pro Forma Adjustment to Operation and Maintenance Expense
Twelve Months Ended December 31, 2007

This pro forma adjustment decreased 2007 test year O&M expense to relect the ongoing level of bad debt expense per the Bailly N1 Refund Order, Cause No. 37972.

Line No.	Description	Amount
	A	B
1	Decrease in Pro Forma Test Year O&M Expense	$ (200,000)

Summary of Rate Base Updates
December 31, 2007 As Updated

Line No	Description	Exhibit No.	Debit	Credit
	A	B	C	D
1	Rate Base Updates:			
2	DH Mitchell Plant Retirement			
3	Mitchell Units 4, 5, 6, 11, and 9A- Plant-in-Service	RB - 1	$ -	$ 175,909,015
4	Mitchell Units 4, 5, 6, 11 and 9A - Accumulated Depreciation	RB - 2	$ 178,072,088	$ -
5	Michigan City 2&3 Plant Retirement			
6	MC Units 2 & 3 - Plant-In-Service	RB - 3	$ -	$ 19,395,755
7	MC Units 2 & 3 - Accumulated Depreciation	RB - 4	$ 18,096,416	$ -
8	Seven Factor Test			
9	Gross Plant	RB - 5	$ 123,243,366	$ 123,243,367
10	Accumulated Depreciation and Amortization	RB - 6	$ 48,919,630	$ 48,919,630
11	All Other Transfers / Corrections			
12	Electric			
13	Gross Plant	RB - 7	$ 148,573,386	$ 43,343,552
14	Accumulated Depreciation	RB - 8	$ 17,622,081	$ 130,397,808
15	Common			
16	Gross Plant	RB - 9	$ 1,180,329	$ -
17	Accumulated Depreciation	RB - 10	$ -	$ 1,335,790
18	Total Rate Base Updates		$ 535,707,296	$ 542,544,917
19	Net Increase / (Decrease)		$ (6,837,621)	

Attachment 3

BAILLY GENERATING STATION

The Bailly Generating Station is located on a 100-acre site on the shore of Lake Michigan in Porter County, Indiana. The stations two base-load and one peaking units came on-line over a six-year period ending in 1968. The units are equipped with various environmental control technologies, including Flue Gas Desulfurization (FGD) to reduce sulfur dioxide (SO_2) and Selective Catalytic Reduction (SCR) and Overfire Air (OFA) systems to reduce nitrogen oxide emissions as required by law. The individual unit characteristics of the Bailly Generating Station are as follows:

BAILLY GENERATING UNIT INFORMATION

		UNIT 7	UNIT 8	UNIT 10
NET LOAD				
	MIN (MW)	100	200	---
	MAX (MW)	160	320	31
BOILER		Babcock & Wilcox	Babcock & Wilcox	----
BURNERS		4 Cyclone	8 Cyclone	----
MAIN FUEL		COAL	COAL	GAS
TURBINE		General Electric	General Electric	Westinghouse
FRAME		D6	G2	W301G
IN-SERVICE		11/30/62	7/31/68	11/30/68
ENVIRONMENTAL CONTROLS		FGD OFA SCR	FGD SCR OFA	 ---- ----

NORWAY HYDROELECTRIC DAM

Norway Hydroelectric Dam is located near Monticello, Indiana on the Tippecanoe River. The dam creates Lake Shafer, approximately 10 miles long with a maximum depth of 30 feet, which functions as its reservoir. Norway Hydro has 4 generating units capable of producing up to 7,200 kW of electricity per hour. However, Norway Hydro output is dependent on river flow and the typical maximum plant output is 4 MW. The individual unit characteristics of the Norway Hydroelectric Dam are as follows:

NORWAY HYDROELECTRIC DAM INFORMATION

		UNIT 1	UNIT 2	UNIT 3	UNIT 4
NET LOAD					
	MIN (kW)	---	---	---	---
	MAX (kW)	2,000	2,000	2,000	1,200
IN-SERVICE		1923	1923	1923	1923
MAIN FUEL		WATER	WATER	WATER	WATER

BAILLY GENERATING STATION

The Bailly Generating Station is located on a 100-acre site on the shore of Lake Michigan in Porter County, Indiana. The stations two base-load and one peaking units came on-line over a six-year period ending in 1968. The units are equipped with various environmental control technologies, including Flue Gas Desulfurization (FGD) to reduce sulfur dioxide (SO_2) and Selective Catalytic Reduction (SCR) and Overfire Air (OFA) systems to reduce nitrogen oxide emissions as required by law. The individual unit characteristics of the Bailly Generating Station are as follows:

BAILLY GENERATING UNIT INFORMATION

		UNIT 7	UNIT 8	UNIT 10
NET LOAD				
	MIN (MW)	100	200	---
	MAX (MW)	160	320	31
BOILER		Babcock & Wilcox	Babcock & Wilcox	----
BURNERS		4 Cyclone	8 Cyclone	----
MAIN FUEL		COAL	COAL	GAS
TURBINE		General Electric	General Electric	Westinghouse
FRAME		D6	G2	W301G
IN-SERVICE		11/30/62	7/31/68	11/30/68
ENVIRONMENTAL CONTROLS		FGD OFA SCR	FGD SCR OFA	 ---- ----

NORWAY HYDROELECTRIC DAM

Norway Hydroelectric Dam is located near Monticello, Indiana on the Tippecanoe River. The dam creates Lake Shafer, approximately 10 miles long with a maximum depth of 30 feet, which functions as its reservoir. Norway Hydro has 4 generating units capable of producing up to 7,200 kW of electricity per hour. However, Norway Hydro output is dependent on river flow and the typical maximum plant output is 4 MW. The individual unit characteristics of the Norway Hydroelectric Dam are as follows:

NORWAY HYDROELECTRIC DAM INFORMATION

		UNIT 1	UNIT 2	UNIT 3	UNIT 4
NET LOAD					
	MIN (kW)	---	---	---	---
	MAX (kW)	2,000	2,000	2,000	1,200
IN-SERVICE		1923	1923	1923	1923
MAIN FUEL		WATER	WATER	WATER	WATER

Attachment 4

NORTHERN INDIANA PUBLIC SERVICE COMPANY
COST OF SERVICE STUDY
(ELECTRIC OPERATIONS)
PRO FORMA TEST YEAR ENDED DECEMBER 31, 2007
REVENUE REQUIREMENT AT PARITY ROR

Line No		Total Company (A)	Rate 511 Residential (B)	Rate 521 GS Small (C)	Rate 523 GS Medium (D)	Rate 526 Off-Peak (E)	Rate 527 Ltd. Prod. Lrg (F)	Rate 533 GS large (G)	Rate 534 Industral Lrg (H)
	TOTAL COST OF SERVICE								
	(REVENUE-RELATED DISTRIBUTED)								
1	PRODUCTION								
2	FIXED	434,206,577	155,851,464	11,070,676	59,955,931	4,028,494	2,879,700	85,445,815	94,012,843
3	VARIABLE	73,029,194	15,979,528	1,839,595	9,290,362	968,510	1,235,380	15,234,341	19,178,330
4									
5	TRANSMISSION SUBSTATIONS	83,370,791	22,587,510	2,067,230	11,311,140	974,594	583,280	16,812,953	20,751,463
6	TRANSMISSION LINES	33,851,859	9,187,714	840,512	4,595,910	395,812	236,334	6,828,807	8,417,773
7									
8	DISTRIB. SUBSTATIONS	36,778,130	16,627,617	1,266,322	6,611,176	638,351	990,078	8,912,270	747,124
9	DISTRIB. SUBSTATIONS - RAILROAD	670,949	0	0	0	0	0	0	0
10									
11	DISTRIBUTION LINES PRIMARY - DEMAND	90,407,587	40,863,756	3,113,636	16,254,342	1,569,161	2,435,722	21,912,540	1,837,379
12	DISTRIBUTION LINES SECONDARY - DEMAND	39,002,092	21,167,742	3,395,433	9,693,766	25,391	0	3,914,826	0
13	LINE TRANSFORMERS - DEMAND	22,691,824	12,960,005	984,771	5,000,857	22,255	0	2,996,998	0
14									
15	SERVICES	9,913,128	8,452,262	814,941	549,359	181	0	63,934	0
16	METERS -GENERAL	19,845,628	12,439,853	2,193,306	2,692,421	55,351	6,890	1,906,949	262,209
17	STREET LIGHTING	4,854,669	0	0	0	0	0	0	0
18	DUSK-TO-DAWN LIGHTING	2,368,404	0	0	0	0	0	0	0
19	METER READING	10,396,720	5,763,109	598,282	506,590	40,158	3,649	3,405,833	46,920
20	BILLING & COLLECTING	24,958,536	19,954,267	2,077,544	589,549	613,254	31,817	699,954	818,443
21	CUSTOMER ACCOUNTS OTHER	219,987	188,790	19,590	5,520	5	0	445	6
22	CUSTOMER INFORMATION	1,568,624	262,319	188,136	148,655	41,738	0	444,974	463,869
23	SALES EXPENSE	3,761,296	3,227,713	335,056	94,547	90	8	7,627	105
24	DIRECT TO RETAIL	0	0	0	0	0	0	0	0
25	DIRECT TO WHOLESALE	0	0	0	0	0	0	0	0
26	REVENUE - OTHER (UNCOLLECTIBLE ACCTS)	0	0	0	0	0	0	0	0
27									
28	REVENUE TAXES	0	0	0	0	0	0	0	0
29									
30	TOTAL COST OF SERVICE FROM RATES	891,895,994	345,513,649	30,805,030	127,300,127	9,373,345	8,402,859	168,588,264	146,536,464

NORTHERN INDIANA PUBLIC SERVICE COMPANY
COST OF SERVICE STUDY
(ELECTRIC OPERATIONS)
PRO FORMA TEST YEAR ENDED DECEMBER 31, 2007
REVENUE REQUIREMENT AT PARITY ROR

Line No		Rate 536 Interrupt. Ind.	Rate 541 Water Pumpg	Rate 544 Railroad	Rate 550 Street Ltg	Rate 555 Traffic Ltg	Rate 560 Dusk-to-Dawn	Interdept'l
		(I)	(J)	(K)	(L)	(M)	(N)	(O)
	TOTAL COST OF SERVICE *(REVENUE-RELATED DISTRIBUTED)*							
1	PRODUCTION							
2	FIXED	18,342,447	446,575	210,829	274,981	175,377	78,013	1,433,433
3	VARIABLE	8,538,696	117,067	80,219	230,674	42,758	65,397	228,337
4								
5	TRANSMISSION SUBSTATIONS	7,724,191	107,280	83,044	96,944	36,727	26,266	208,169
6	TRANSMISSION LINES	3,121,992	43,647	33,722	39,439	14,927	10,694	84,576
7								
8	DISTRIB. SUBSTATIONS	0	519,931	0	174,012	16,227	46,487	228,534
9	DISTRIB. SUBSTATIONS - RAILROAD	0	0	670,949	0	0	0	0
10								
11	DISTRIBUTION LINES PRIMARY - DEMAND	0	1,277,416	0	427,895	39,907	114,196	561,637
12	DISTRIBUTION LINES SECONDARY - DEMAND	0	522,587	0	143,985	13,428	38,440	86,494
13	LINE TRANSFORMERS - DEMAND	0	364,367	0	135,625	12,643	36,251	178,051
14								
15	SERVICES	0	32,453	0	0	0	0	0
16	METERS -GENERAL	113,928	172,920	0	0	0	0	1,800
17	STREET LIGHTING	0	0	0	4,613,286	241,383	0	0
18	DUSK-TO-DAWN LIGHTING	0	0	0	0	0	2,368,404	0
19	METER READING	18,246	9,420	3,677	0	0	0	835
20	BILLING & COLLECTING	252	32,618	458	21,963	1,813	116,605	0
21	CUSTOMER ACCOUNTS OTHER	2	309	0	832	69	4,419	0
22	CUSTOMER INFORMATION	1	17,308	0	254	21	1,349	0
23	SALES EXPENSE	41	5,276	8	14,212	1,173	75,442	0
24	DIRECT TO RETAIL	0	0	0	0	0	0	0
25	DIRECT TO WHOLESALE	0	0	0	0	0	0	0
26	REVENUE - OTHER (UNCOLLECTIBLE ACCTS)	0	0	0	0	0	0	0
27								
28	REVENUE TAXES	0	0	0	0	0	0	0
29								
30	TOTAL COST OF SERVICE FROM RATES	37,859,797	3,669,170	1,082,907	6,174,102	596,451	2,981,962	3,011,865

NORTHERN INDIANA PUBLIC SERVICE COMPANY
COST OF SERVICE STUDY
(ELECTRIC OPERATIONS)
PRO FORMA TEST YEAR ENDED DECEMBER 31, 2007
STEP 1 REVENUE REQUIREMENT (AT MODERATED ROR)

Line No		Rate 536 Interrupt. Ind.	Rate 541 Water Pumpg	Rate 544 Railroad	Rate 550 Street Ltg	Rate 555 Traffic Ltg	Rate 560 Dusk-to-Dawn	Interdept'l
		(I)	(J)	(K)	(L)	(M)	(N)	(O)
	REVENUE REQUIREMENT AT TARGET ROR							
	EARNED RATE OF RETURN	2.64%	-1.75%	12.39%	14.81%	17.23%	-4.19%	-2.38%
1	RATE BASE	92,342,480	10,846,090	3,675,615	11,714,341	1,329,084	5,284,498	8,328,540
2								
3	TARGET RATE OF RETURN	0.04540	0.01615	0.12210	0.10494	0.10494	0.10494	(0.02385)
4								
5	REQUIRED RETURN ON RATE BASE	4,192,308	175,186	448,785	1,229,284	139,472	554,547	-198,621
6	EARNED RETURN ON RATE BASE	2,437,780	-189,503	455,522	1,734,719	229,027	-221,608	-198,621
7								
8	REQUIRED INCREASE IN RETURN	1,754,528	364,689	-6,737	-505,435	-89,556	776,155	0
9								
10	ASSOC. INCR IN INCOME TAXES	1,199,408	249,304	-4,606	-345,519	-61,221	530,585	0
11								
12	TOTAL INCREASE IN RETURN & INC TAXES	2,953,935	613,993	-11,343	-850,953	-150,776	1,306,740	0
13								
14	INCREASE IN REVENUE-RELATED	52,523	10,917	-202	-15,130	-2,681	23,235	0
15								
16	OPERATING EXPENSES PER COSS	27,449,185	2,316,597	641,068	4,771,972	442,084	2,398,788	1,981,789
17	INCOME TAXES PER COSS	284,366	-290,654	255,694	1,004,930	136,103	-229,863	-259,551
18	RETURN PER COSS	2,437,780	-189,503	455,522	1,734,719	229,027	-221,608	-198,621
19								
20	TOTAL REVENUE REQUIREMENT	33,177,789	2,461,350	1,340,740	6,645,538	653,757	3,277,292	1,523,617
21	LESS OTHER REVENUES	1,330,908	41,999	14,101	39,094	8,253	100,295	42,324
22	REVENUE REQUIREMENT FROM RATES	31,846,881	2,419,350	1,326,638	6,606,443	645,504	3,176,997	1,481,293
23								
24	PRESENT RATE REVENUES	28,840,423	1,794,440	1,338,183	7,472,527	798,961	1,847,022	1,481,293
25								
26	REVENUE INCREASE TO BASE RATES	3,006,458	624,910	-11,545	-866,084	-153,457	1,329,975	0
27	PERCENT REVENUE INCREASE	10.42%	34.82%	-0.86%	-11.59%	-19.21%	72.01%	0.00%
28								

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NORTHERN INDIANA PUBLIC SERVICE COMPANY
COST OF SERVICE STUDY
(ELECTRIC OPERATIONS)
PRO FORMA TEST YEAR ENDED DECEMBER 31, 2007
STEP 1 REVENUE REQUIREMENT (AT MODERATED ROR)

Line No		Total Company	Rate 511 Residential	Rate 521 GS Small	Rate 523 GS Medium	Rate 526 Off-Peak	Rate 527 Ltd. Prod. Lrg	Rate 533 GS large	Rate 534 Industral Lrg
		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
	TOTAL COST OF SERVICE (REVENUE-RELATED DISTRIBUTED)								
1	PRODUCTION								
2	FIXED	434,983,579	136,013,583	15,600,236	68,226,003	3,343,242	3,729,872	92,178,276	98,893,945
3	VARIABLE	73,242,690	15,347,260	2,068,003	9,678,919	917,945	1,347,252	15,599,205	19,490,894
4									
5	TRANSMISSION SUBSTATIONS	83,938,899	19,251,645	3,050,074	13,123,866	782,162	783,098	18,351,710	22,000,122
6	TRANSMISSION LINES	34,122,638	7,617,347	1,303,760	5,450,384	305,158	330,476	7,554,059	9,005,314
7									
8	DISTRIB. SUBSTATIONS	36,777,846	13,468,578	2,042,745	7,978,205	475,853	1,428,164	9,964,740	805,023
9	DISTRIB. SUBSTATIONS - RAILROAD	847,955	0	0	0	0	0	0	0
10									
11	DISTRIBUTION LINES PRIMARY - DEMAND	90,385,207	35,977,050	4,309,679	18,359,517	1,318,427	3,111,411	23,533,881	1,927,063
12	DISTRIBUTION LINES SECONDARY - DEMAND	39,178,395	18,141,614	4,957,799	11,197,858	20,535	0	4,261,799	0
13	LINE TRANSFORMERS - DEMAND	21,854,609	10,188,309	1,665,171	6,166,450	15,871	0	3,395,975	0
14									
15	SERVICES	9,006,897	6,997,523	1,267,269	652,224	139	0	70,772	0
16	METERS -GENERAL	19,620,809	10,912,978	3,058,117	3,050,137	46,283	8,847	2,051,640	275,315
17	STREET LIGHTING	5,148,188	0	0	0	0	0	0	0
18	DUSK-TO-DAWN LIGHTING	2,515,495	0	0	0	0	0	0	0
19	METER READING	10,344,831	5,546,461	668,668	526,618	38,178	3,960	3,482,857	47,641
20	BILLING & COLLECTING	24,418,083	19,108,346	2,354,354	615,959	579,049	34,877	717,887	832,623
21	CUSTOMER ACCOUNTS OTHER	218,162	185,965	20,457	5,602	5	0	449	6
22	CUSTOMER INFORMATION	1,600,002	252,582	209,981	154,455	39,706	0	454,906	470,911
23	SALES EXPENSE	3,691,710	3,116,664	371,011	97,956	86	9	7,784	107
24	DIRECT TO RETAIL	0	0	0	0	0	0	0	0
25	DIRECT TO WHOLESALE	0	0	0	0	0	0	0	0
26	REVENUE - OTHER (UNCOLLECTIBLE ACCTS)	0	0	0	0	0	0	0	0
27									
28	REVENUE TAXES	0	0	0	0	0	0	0	0
29									
30	TOTAL COST OF SERVICE FROM RATES	891,895,994	302,125,904	42,947,324	145,284,153	7,882,638	10,777,965	181,625,941	153,748,962

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NORTHERN INDIANA PUBLIC SERVICE COMPANY
COST OF SERVICE STUDY
(ELECTRIC OPERATIONS)
PRO FORMA TEST YEAR ENDED DECEMBER 31, 2007
STEP 1 REVENUE REQUIREMENT (AT MODERATED ROR)

Line No		Rate 536 Interrupt. Ind.	Rate 541 Water Pumpg	Rate 544 Railroad	Rate 550 Street Ltg	Rate 555 Traffic Ltg	Rate 560 Dusk-to-Dawn	Interdept'l
		(I)	(J)	(K)	(L)	(M)	(N)	(O)
	TOTAL COST OF SERVICE (REVENUE-RELATED DISTRIBUTED)							
1	PRODUCTION							
2	FIXED	15,128,925	309,604	248,027	301,784	192,567	85,753	731,763
3	VARIABLE	8,060,609	106,102	84,478	237,287	44,010	67,385	193,342
4								
5	TRANSMISSION SUBSTATIONS	6,158,907	69,061	100,072	107,947	40,914	29,293	90,029
6	TRANSMISSION LINES	2,386,116	25,638	41,752	44,633	16,902	12,120	28,979
7								
8	DISTRIB. SUBSTATIONS	0	281,339	0	199,538	18,617	53,382	61,663
9	DISTRIB. SUBSTATIONS - RAILROAD	0	0	847,955	0	0	0	0
10								
11	DISTRIBUTION LINES PRIMARY - DEMAND	0	909,510	0	467,013	43,578	124,835	303,243
12	DISTRIBUTION LINES SECONDARY - DEMAND	0	342,424	0	159,789	14,909	42,725	38,943
13	LINE TRANSFORMERS - DEMAND	0	176,061	0	158,061	14,742	42,303	31,666
14								
15	SERVICES	0	18,969	0	0	0	0	0
16	METERS -GENERAL	94,754	121,787	0	0	0	0	951
17	STREET LIGHTING	0	0	0	4,892,085	256,103	0	0
18	DUSK-TO-DAWN LIGHTING	0	0	0	0	0	2,515,495	0
19	METER READING	17,292	8,583	3,861	0	0	0	714
20	BILLING & COLLECTING	237	29,338	484	22,642	1,870	120,417	0
21	CUSTOMER ACCOUNTS OTHER	2	298	0	840	69	4,468	0
22	CUSTOMER INFORMATION	1	15,789	0	261	22	1,388	0
23	SALES EXPENSE	39	4,848	9	14,562	1,202	77,434	0
24	DIRECT TO RETAIL	0	0	0	0	0	0	0
25	DIRECT TO WHOLESALE	0	0	0	0	0	0	0
26	REVENUE - OTHER (UNCOLLECTIBLE ACCTS)	0	0	0	0	0	0	0
27								
28	REVENUE TAXES	0	0	0	0	0	0	0
29								
30	TOTAL COST OF SERVICE FROM RATES	31,846,881	2,419,350	1,326,638	6,606,443	645,504	3,176,997	1,481,293

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NORTHERN INDIANA PUBLIC SERVICE COMPANY
COST OF SERVICE STUDY
(ELECTRIC OPERATIONS)
PRO FORMA TEST YEAR ENDED DECEMBER 31, 2007
STEP 1 REVENUE REQUIREMENT (AT MODERATED ROR)

Line No		Rate 536 Interrupt. Ind.	Rate 541 Water Pumpg	Rate 544 Railroad	Rate 550 Street Ltg	Rate 555 Traffic Ltg	Rate 560 Dusk-to-Dawn	Interdept'l
		(I)	(J)	(K)	(L)	(M)	(N)	(O)
	BILLING DETERMINANTS							
1	*KWH SALES*	2,084,025,091	25,231,213	18,905,250	48,891,853	9,129,140	14,252,921	48,840,763
2								
3	*AVERAGE MONTH BILLING KW*							
4	*TRANSMISSION*	249,900	0	0	0	0	0	0
5	*PRIMARY*	0	0	0	0	0	0	0
6	*SECONDARY*	0	0	0	0	0	0	0
7								
8	*AVG. NO. OF CUSTOMERS*	5	644	1	1,725	143	9,429	0
9								
10	***UNIT COSTS***							
11		$/KW/MO.	$/KWH/MO.	$/KW/MO.	$/KWH/MO.	$/KWH/MO.	$/KWH/MO.	
12	*PRODUCTION FIXED*	$ 5.04	$ 0.01227	$ -	$ 0.00617	$ 0.02109	$ 0.00602	
13								
14	*PRODUCTION VARIABLE*	$ 0.00387	$ 0.00421	$ 0.00447	$ 0.00485	$ 0.00482	$ 0.00473	
15								
16	*TRANSMISSION*	$ 2.85	$ 0.00375	$ -	$ 0.00312	$ 0.00633	$ 0.00291	
17								
18	*DISTRIBUTION*							
19	*PRIMARY*	$ -	$ 0.04720	$ -	$ 0.01363	$ 0.00681	$ 0.01250	
20	*SECONDARY*	$ -	$ 0.02055	$ -	$ 0.00650	$ 0.00325	$ 0.00597	
21								
22	*DISTRIBUTION TOTAL*	$ -	$ 0.06775	$ -	$ 0.02013	$ 0.01006	$ 0.01847	
23								
24	*TOTAL $/KWH*	$ 0.00387	$ 0.08798	$ 0.00447	$ 0.03428	$ 0.04231	$ 0.03212	
25	*TOTAL $/KW (@ LOWEST SERVICE LEVEL)*	$ 7.89	$ -	$ -	$ -	$ -	$ -	
26								
27	*CUSTOMER ($/CUSTOMER/MONTH)*							
28	*SERVICES*	$ -	$ 2.45	$ -	$ -	$ -	$ -	
29	*METERS*	1,579.24	15.76	-	-	-	-	
30	*STREET LIGHTING*	-	-	-	236.33	149.24	-	
31	*METER READING*	288.20	1.11	321.72	-	-	-	
32	*BILLING & COLLECTING*	3.96	3.80	40.34	1.09	1.09	1.06	
33	*CUSTOMER ACCOUNTS OTHER*	0.04	0.04	0.04	0.04	0.04	0.04	
34	*CUSTOMER INFORMATION*	0.01	2.04	0.01	0.01	0.01	0.01	
35	*SALES EXPENSE*	0.65	0.63	0.72	0.70	0.70	0.68	
36								
37	*CUSTOMER TOTAL*	**$ 1,872.08**	**$ 25.83**	**$ 362.83**	**$ 238.18**	**$ 151.09**	**$ 1.80**	

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NORTHERN INDIANA PUBLIC SERVICE COMPANY
COST OF SERVICE STUDY
(ELECTRIC OPERATIONS)
PRO FORMA TEST YEAR ENDED DECEMBER 31, 2007
REVENUE REQUIREMENT AT PARITY ROR

Line No		Total Company	Rate 511 Residential	Rate 521 GS Small	Rate 523 GS Medium	Rate 526 Off-Peak	Rate 527 Ltd. Prod. Lrg	Rate 533 GS large	Rate 534 Industral Lrg
		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
	TOTAL COST OF SERVICE *(REVENUE-RELATED DISTRIBUTED)*								
1	PRODUCTION								
2	FIXED	434,206,577	155,851,464	11,070,676	59,955,931	4,028,494	2,879,700	85,445,815	94,012,843
3	VARIABLE	73,029,194	15,979,528	1,839,595	9,290,362	968,510	1,235,380	15,234,341	19,178,330
4									
5	TRANSMISSION SUBSTATIONS	83,370,791	22,587,510	2,067,230	11,311,140	974,594	583,280	16,812,953	20,751,463
6	TRANSMISSION LINES	33,851,859	9,187,714	840,512	4,595,910	395,812	236,334	6,828,807	8,417,773
7									
8	DISTRIB. SUBSTATIONS	36,778,130	16,627,617	1,266,322	6,611,176	638,351	990,078	8,912,270	747,124
9	DISTRIB. SUBSTATIONS - RAILROAD	670,949	0	0	0	0	0	0	0
10									
11	DISTRIBUTION LINES PRIMARY - DEMAND	90,407,587	40,863,756	3,113,636	16,254,342	1,569,161	2,435,722	21,912,540	1,837,379
12	DISTRIBUTION LINES SECONDARY - DEMAND	39,002,092	21,167,742	3,395,433	9,693,766	25,391	0	3,914,826	0
13	LINE TRANSFORMERS - DEMAND	22,691,824	12,960,005	984,771	5,000,857	22,255	0	2,996,998	0
14									
15	SERVICES	9,913,128	8,452,262	814,941	549,359	181	0	63,934	0
16	METERS -GENERAL	19,845,628	12,439,853	2,193,306	2,692,421	55,351	6,890	1,906,949	262,209
17	STREET LIGHTING	4,854,669	0	0	0	0	0	0	0
18	DUSK-TO-DAWN LIGHTING	**2,368,404**	0	0	0	0	0	0	0
19	METER READING	10,396,720	5,763,109	598,282	506,590	40,158	3,649	3,405,833	46,920
20	BILLING & COLLECTING	24,958,536	19,954,267	2,077,544	589,549	613,254	31,817	699,954	818,443
21	CUSTOMER ACCOUNTS OTHER	219,987	188,790	19,590	5,520	5	0	445	6
22	CUSTOMER INFORMATION	1,568,624	262,319	188,136	148,655	41,738	0	444,974	463,869
23	SALES EXPENSE	3,761,296	3,227,713	335,056	94,547	90	8	7,627	105
24	DIRECT TO RETAIL	0	0	0	0	0	0	0	0
25	DIRECT TO WHOLESALE	0	0	0	0	0	0	0	0
26	REVENUE - OTHER (UNCOLLECTIBLE ACCTS)	0	0	0	0	0	0	0	0
27									
28	REVENUE TAXES	0	0	0	0	0	0	0	0
29									
30	TOTAL COST OF SERVICE FROM RATES	**891,895,994**	345,513,649	30,805,030	127,300,127	9,373,345	8,402,859	168,588,264	146,536,464

NORTHERN INDIANA PUBLIC SERVICE COMPANY
COST OF SERVICE STUDY
(ELECTRIC OPERATIONS)
PRO FORMA TEST YEAR ENDED DECEMBER 31, 2007
REVENUE REQUIREMENT AT PARITY ROR

Line No		Rate 536 Interrupt. Ind.	Rate 541 Water Pumpg	Rate 544 Railroad	Rate 550 Street Ltg	Rate 555 Traffic Ltg	Rate 560 Dusk-to-Dawn	Interdept'l
		(I)	(J)	(K)	(L)	(M)	(N)	(O)
	TOTAL COST OF SERVICE *(REVENUE-RELATED DISTRIBUTED)*							
1	PRODUCTION							
2	FIXED	18,342,447	446,575	210,829	274,981	175,377	78,013	1,433,433
3	VARIABLE	8,538,696	117,067	80,219	230,674	42,758	65,397	228,337
4								
5	TRANSMISSION SUBSTATIONS	7,724,191	107,280	83,044	96,944	36,727	26,266	208,169
6	TRANSMISSION LINES	3,121,992	43,647	33,722	39,439	14,927	10,694	84,576
7								
8	DISTRIB. SUBSTATIONS	0	519,931	0	174,012	16,227	46,487	228,534
9	DISTRIB. SUBSTATIONS - RAILROAD	0	0	670,949	0	0	0	0
10								
11	DISTRIBUTION LINES PRIMARY - DEMAND	0	1,277,416	0	427,895	39,907	114,196	561,637
12	DISTRIBUTION LINES SECONDARY - DEMAND	0	522,587	0	143,985	13,428	38,440	86,494
13	LINE TRANSFORMERS - DEMAND	0	364,367	0	135,625	12,643	36,251	178,051
14								
15	SERVICES	0	32,453	0	0	0	0	0
16	METERS -GENERAL	113,928	172,920	0	0	0	0	1,800
17	STREET LIGHTING	0	0	0	4,613,286	241,383	0	0
18	DUSK-TO-DAWN LIGHTING	0	0	0	0	0	**2,368,404**	0
19	METER READING	18,246	9,420	3,677	0	0	0	835
20	BILLING & COLLECTING	252	32,618	458	21,963	1,813	116,605	0
21	CUSTOMER ACCOUNTS OTHER	2	309	0	832	69	4,419	0
22	CUSTOMER INFORMATION	1	17,308	0	254	21	1,349	0
23	SALES EXPENSE	41	5,276	8	14,212	1,173	75,442	0
24	DIRECT TO RETAIL	0	0	0	0	0	0	0
25	DIRECT TO WHOLESALE	0	0	0	0	0	0	0
26	REVENUE - OTHER (UNCOLLECTIBLE ACCTS)	0	0	0	0	0	0	0
27								
28	REVENUE TAXES	0	0	0	0	0	0	0
29								
30	TOTAL COST OF SERVICE FROM RATES	37,859,797	3,669,170	1,082,907	6,174,102	596,451	**2,981,962**	3,011,865

NORTHERN INDIANA PUBLIC SERVICE COMPANY
COST OF SERVICE STUDY
(ELECTRIC OPERATIONS)
PRO FORMA TEST YEAR ENDED DECEMBER 31, 2007
STEP 1 REVENUE REQUIREMENT (AT MODERATED ROR)

Line No		Rate 536 Interrupt. Ind.	Rate 541 Water Pumpg	Rate 544 Railroad	Rate 550 Street Ltg	Rate 555 Traffic Ltg	Rate 560 Dusk-to-Dawn	Interdept'l
		(I)	(J)	(K)	(L)	(M)	(N)	(O)
	REVENUE REQUIREMENT AT TARGET ROR							
	EARNED RATE OF RETURN	2.64%	-1.75%	12.39%	14.81%	17.23%	-4.19%	-2.38%
1	RATE BASE	92,342,480	10,846,090	3,675,615	11,714,341	1,329,084	5,284,498	8,328,540
2								
3	TARGET RATE OF RETURN	0.04540	0.01615	0.12210	0.10494	0.10494	0.10494	(0.02385)
4								
5	REQUIRED RETURN ON RATE BASE	4,192,308	175,186	448,785	1,229,284	139,472	554,547	-198,621
6	EARNED RETURN ON RATE BASE	2,437,780	-189,503	455,522	1,734,719	229,027	-221,608	-198,621
7								
8	REQUIRED INCREASE IN RETURN	1,754,528	364,689	-6,737	-505,435	-89,556	776,155	0
9								
10	ASSOC. INCR IN INCOME TAXES	1,199,408	249,304	-4,606	-345,519	-61,221	530,585	0
11								
12	TOTAL INCREASE IN RETURN & INC TAXES	2,953,935	613,993	-11,343	-850,953	-150,776	1,306,740	0
13								
14	INCREASE IN REVENUE-RELATED	52,523	10,917	-202	-15,130	-2,681	23,235	0
15								
16	OPERATING EXPENSES PER COSS	27,449,185	2,316,597	641,068	4,771,972	442,084	2,398,788	1,981,789
17	INCOME TAXES PER COSS	284,366	-290,654	255,694	1,004,930	136,103	-229,863	-259,551
18	RETURN PER COSS	2,437,780	-189,503	455,522	1,734,719	229,027	-221,608	-198,621
19								
20	TOTAL REVENUE REQUIREMENT	33,177,789	2,461,350	1,340,740	6,645,538	653,757	3,277,292	1,523,617
21	LESS OTHER REVENUES	1,330,908	41,999	14,101	39,094	8,253	100,295	42,324
22	REVENUE REQUIREMENT FROM RATES	31,846,881	2,419,350	1,326,638	6,606,443	645,504	3,176,997	1,481,293
23								
24	PRESENT RATE REVENUES	28,840,423	1,794,440	1,338,183	7,472,527	798,961	1,847,022	1,481,293
25								
26	REVENUE INCREASE TO BASE RATES	3,006,458	624,910	-11,545	-866,084	-153,457	1,329,975	0
27	PERCENT REVENUE INCREASE	10.42%	34.82%	-0.86%	-11.59%	-19.21%	72.01%	0.00%
28								

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NORTHERN INDIANA PUBLIC SERVICE COMPANY
COST OF SERVICE STUDY
(ELECTRIC OPERATIONS)
PRO FORMA TEST YEAR ENDED DECEMBER 31, 2007
STEP 1 REVENUE REQUIREMENT (AT MODERATED ROR)

Line No		Total Company (A)	Rate 511 Residential (B)	Rate 521 GS Small (C)	Rate 523 GS Medium (D)	Rate 526 Off-Peak (E)	Rate 527 Ltd. Prod. Lrg (F)	Rate 533 GS large (G)	Rate 534 Industral Lrg (H)
	TOTAL COST OF SERVICE *(REVENUE-RELATED DISTRIBUTED)*								
1	PRODUCTION								
2	FIXED	**434,983,579**	136,013,583	15,600,236	68,226,003	3,343,242	3,729,872	92,178,276	98,893,945
3	VARIABLE	**73,242,690**	15,347,260	2,068,003	9,678,919	917,945	1,347,252	15,599,205	19,490,894
4									
5	TRANSMISSION SUBSTATIONS	**83,938,899**	19,251,645	3,050,074	13,123,866	782,162	783,098	18,351,710	22,000,122
6	TRANSMISSION LINES	**34,122,638**	7,617,347	1,303,760	5,450,384	305,158	330,476	7,554,059	9,005,314
7									
8	DISTRIB. SUBSTATIONS	**36,777,846**	13,468,578	2,042,745	7,978,205	475,853	1,428,164	9,964,740	805,023
9	DISTRIB. SUBSTATIONS - RAILROAD	**847,955**	0	0	0	0	0	0	0
10									
11	DISTRIBUTION LINES PRIMARY - DEMAND	**90,385,207**	35,977,050	4,309,679	18,359,517	1,318,427	3,111,411	23,533,881	1,927,063
12	DISTRIBUTION LINES SECONDARY - DEMAND	**39,178,395**	18,141,614	4,957,799	11,197,858	20,535	0	4,261,799	0
13	LINE TRANSFORMERS - DEMAND	**21,854,609**	10,188,309	1,665,171	6,166,450	15,871	0	3,395,975	0
14									
15	SERVICES	**9,006,897**	6,997,523	1,267,269	652,224	139	0	70,772	0
16	METERS -GENERAL	**19,620,809**	10,912,978	3,058,117	3,050,137	46,283	8,847	2,051,640	275,315
17	STREET LIGHTING	**5,148,188**	0	0	0	0	0	0	0
18	DUSK-TO-DAWN LIGHTING	**2,515,495**	0	0	0	0	0	0	0
19	METER READING	**10,344,831**	5,546,461	668,668	526,618	38,178	3,960	3,482,857	47,641
20	BILLING & COLLECTING	**24,418,083**	19,108,346	2,354,354	615,959	579,049	34,877	717,887	832,623
21	CUSTOMER ACCOUNTS OTHER	**218,162**	185,965	20,457	5,602	5	0	449	6
22	CUSTOMER INFORMATION	**1,600,002**	252,582	209,981	154,455	39,706	0	454,906	470,911
23	SALES EXPENSE	**3,691,710**	3,116,664	371,011	97,956	86	9	7,784	107
24	DIRECT TO RETAIL	0	0	0	0	0	0	0	0
25	DIRECT TO WHOLESALE	0	0	0	0	0	0	0	0
26	REVENUE - OTHER (UNCOLLECTIBLE ACCTS)	0	0	0	0	0	0	0	0
27									
28	REVENUE TAXES	0	0	0	0	0	0	0	0
29									
30	TOTAL COST OF SERVICE FROM RATES	**891,895,994**	302,125,904	42,947,324	145,284,153	7,882,638	10,777,965	181,625,941	153,748,962

NORTHERN INDIANA PUBLIC SERVICE COMPANY
COST OF SERVICE STUDY
(ELECTRIC OPERATIONS)
PRO FORMA TEST YEAR ENDED DECEMBER 31, 2007
STEP 1 REVENUE REQUIREMENT (AT MODERATED ROR)

Line No		Rate 536 Interrupt. Ind.	Rate 541 Water Pumpg	Rate 544 Railroad	Rate 550 Street Ltg	Rate 555 Traffic Ltg	Rate 560 Dusk-to-Dawn	Interdept'l
		(I)	(J)	(K)	(L)	(M)	(N)	(O)
	TOTAL COST OF SERVICE *(REVENUE-RELATED DISTRIBUTED)*							
1	PRODUCTION							
2	FIXED	15,128,925	309,604	248,027	301,784	192,567	85,753	731,763
3	VARIABLE	8,060,609	106,102	84,478	237,287	44,010	67,385	193,342
4								
5	TRANSMISSION SUBSTATIONS	6,158,907	69,061	100,072	107,947	40,914	29,293	90,029
6	TRANSMISSION LINES	2,386,116	25,638	41,752	44,633	16,902	12,120	28,979
7								
8	DISTRIB. SUBSTATIONS	0	281,339	0	199,538	18,617	53,382	61,663
9	DISTRIB. SUBSTATIONS - RAILROAD	0	0	847,955	0	0	0	0
10								
11	DISTRIBUTION LINES PRIMARY - DEMAND	0	909,510	0	467,013	43,578	124,835	303,243
12	DISTRIBUTION LINES SECONDARY - DEMAND	0	342,424	0	159,789	14,909	42,725	38,943
13	LINE TRANSFORMERS - DEMAND	0	176,061	0	158,061	14,742	42,303	31,666
14								
15	SERVICES	0	18,969	0	0	0	0	0
16	METERS -GENERAL	94,754	121,787	0	0	0	0	951
17	STREET LIGHTING	0	0	0	4,892,085	256,103	0	0
18	DUSK-TO-DAWN LIGHTING	0	0	0	0	0	2,515,495	0
19	METER READING	17,292	8,583	3,861	0	0	0	714
20	BILLING & COLLECTING	237	29,338	484	22,642	1,870	120,417	0
21	CUSTOMER ACCOUNTS OTHER	2	298	0	840	69	4,468	0
22	CUSTOMER INFORMATION	1	15,789	0	261	22	1,388	0
23	SALES EXPENSE	39	4,848	9	14,562	1,202	77,434	0
24	DIRECT TO RETAIL	0	0	0	0	0	0	0
25	DIRECT TO WHOLESALE	0	0	0	0	0	0	0
26	REVENUE - OTHER (UNCOLLECTIBLE ACCTS)	0	0	0	0	0	0	0
27								
28	REVENUE TAXES	0	0	0	0	0	0	0
29								
30	TOTAL COST OF SERVICE FROM RATES	31,846,881	2,419,350	1,326,638	6,606,443	645,504	3,176,997	1,481,293

Petitioner's Exhibit No. RDG-3
Northern Indiana Public Service Company
Cause No. 43526
Schedule 3.1
Page 2 of 2
CORRECTED
September 24, 2008

Petitioner's Exhibit No. RDG-3
Northern Indiana Public Service Company
Cause No. 43526
Schedule 3.2
Page 2 of 2
CORRECTED
September 24, 2008

NORTHERN INDIANA PUBLIC SERVICE COMPANY
COST OF SERVICE STUDY
(ELECTRIC OPERATIONS)
PRO FORMA TEST YEAR ENDED DECEMBER 31, 2007
STEP 1 REVENUE REQUIREMENT (AT MODERATED ROR)

Line No		Rate 536 Interrupt. Ind.	Rate 541 Water Pumpg	Rate 544 Railroad	Rate 550 Street Ltg	Rate 555 Traffic Ltg	Rate 560 Dusk-to-Dawn	Interdept'l
		(I)	(J)	(K)	(L)	(M)	(N)	(O)
	BILLING DETERMINANTS							
1	KWH SALES	2,084,025,091	25,231,213	18,905,250	48,891,853	9,129,140	14,252,921	48,840,763
2								
3	AVERAGE MONTH BILLING KW							
4	TRANSMISSION	249,900	0	0	0	0	0	0
5	PRIMARY	0	0	0	0	0	0	0
6	SECONDARY	0	0	0	0	0	0	0
7								
8	AVG. NO. OF CUSTOMERS	5	644	1	1,725	143	9,429	0
9								
10	**UNIT COSTS**							
11		$/KW/MO.	$/KWH/MO.	$/KW/MO.	$/KWH/MO.	$/KWH/MO.	$/KWH/MO.	
12	PRODUCTION FIXED	$ 5.04	$ 0.01227	$ -	$ 0.00617	$ 0.02109	$ 0.00602	
13								
14	PRODUCTION VARIABLE	$ 0.00387	$ 0.00421	$ 0.00447	$ 0.00485	$ 0.00482	$ 0.00473	
15								
16	TRANSMISSION	$ 2.85	$ 0.00375	$ -	$ 0.00312	$ 0.00633	$ 0.00291	
17								
18	DISTRIBUTION							
19	PRIMARY	$ -	$ 0.04720	$ -	$ 0.01363	$ 0.00681	$ 0.01250	
20	SECONDARY	$ -	$ 0.02055	$ -	$ 0.00650	$ 0.00325	$ 0.00597	
21								
22	DISTRIBUTION TOTAL	$ -	$ 0.06775	$ -	$ 0.02013	$ 0.01006	$ 0.01847	
23								
24	TOTAL $/KWH	$ 0.00387	$ 0.08798	$ 0.00447	$ 0.03428	$ 0.04231	$ 0.03212	
25	TOTAL $/KW (@ LOWEST SERVICE LEVEL)	$ 7.89	$ -	$ -	$ -	$ -	$ -	
26								
27	CUSTOMER ($/CUSTOMER/MONTH)							
28	SERVICES	$ -	$ 2.45	$ -	$ -	$ -	$ -	
29	METERS	1,579.24	15.76	-	-	-	-	
30	STREET LIGHTING	-	-	-	236.33	149.24	-	
31	METER READING	288.20	1.11	321.72	-	-	-	
32	BILLING & COLLECTING	3.96	3.80	40.34	1.09	1.09	1.06	
33	CUSTOMER ACCOUNTS OTHER	0.04	0.04	0.04	0.04	0.04	0.04	
34	CUSTOMER INFORMATION	0.01	2.04	0.01	0.01	0.01	0.01	
35	SALES EXPENSE	0.65	0.63	0.72	0.70	0.70	0.68	
36								
37	CUSTOMER TOTAL	$ 1,872.08	$ 25.83	$ 362.83	$ 238.18	$ 151.09	$ 1.80	

Attachment 5

<u>Rule 11 – Rendering and Payments of Bills</u>

The proposed Rule 11 is a combination of current Rules 6A, 6B and 7. The Senior Citizen Payment Plan has been expanded to include the legally disabled receiving social security benefits and is now the Social Security Payment Plan. If the customer meets the criteria, their due date can be extended up to ten calendar days.

<u>Rule 12 – Disconnection and Reconnection of Service</u>

The proposed Rule 12 is a combination of current Rules 8, 15 and 19. There were no significant changes to these rules.

<u>Rule 13 – Service Interruptions and Curtailments</u>

The proposed Rule 13 is a combination of current Rules 34 and 35. This rule has been modified to incorporate the changes to our Curtailment and Interruption procedures as a result of being a member of the Midwest ISO, which is discussed in more detail by Mr. Crum.

<u>Rule 14 – Miscellaneous and Non-reoccurring Charges</u>

The proposed Rule 14 includes (1) reconnection fees and (2) a charge to reimburse the Company for non-sufficient and returned payment fees. Reconnection fees are calculated to cover the cost of reconnection of service and vary depending on when the service is provided (during normal working hours, after normal working hours or holidays), as well as whether the reconnection is done at the meter or at the pole. The distinction between

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Attachment 6

GENERAL RULES AND REGULATIONS
Applicable to Electric Service

1. DEFINITIONS (continued)

NN. National Electric Code – The standard for the safe installation of electrical wiring and equipment. It is part of the National Fire Codes series published by the National Fire Protection Association (NFPA).

OO. Non-Sufficient Funds – An account shall be considered to have Non-Sufficient Funds for the following reasons:

1. The Customer's payment is considered delinquent by the banking institution.
2. The Customer has supplied the incorrect bank account number.
3. The Customer's bank account number is no longer available.
4. The Customer has issued a stop payment by the banking institution to the Company.
5. The Customer pays electronically, and a chargeback is subsequently assessed by the Customer's financial institution.
6. Any other instance when the financial institution refuses to honor the tendered payment.

PP. Off-Peak Demand – The Demand taken during Off-Peak Hours.

QQ. Off-Peak Hours - All hours not defined as On-Peak Hours shall be considered Off-Peak hours.

RR. On-Peak Demand - The Demand taken during On-Peak Hours.

SS. On-Peak Hours – Defined as the hours listed below:

Winter classified as October 1 through March 31

On-Peak Hours are those commencing at 1:00 p.m. Central Standard Time (C.S.T.) and ending at 9:00 p.m., Central Standard Time (C.S.T.), Monday through Friday excluding the holidays set forth below.

Summer classified as April 1 through September 30

On-Peak Hours are those commencing at 11:00 a.m. Central Standard Time (C.S.T.) and ending at 7:00 p.m., Central Standard Time (C.S.T.), Monday through Friday excluding the holidays set forth below.

Holidays include New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day and Christmas Day and are considered to be Off-Peak Hours for the entire twenty-four hours. If the holidays listed above occur on a Saturday and the preceding Friday is a legally observed holiday, the entire twenty four hours of such Friday will be considered off-peak hours. If the holiday listed occurs on a Sunday and the following Monday is legally observed as a holiday, the entire twenty-four hours of such Monday will be considered as off-peak hours.

GENERAL RULES AND REGULATIONS
Applicable to Electric Service

1. **DEFINITIONS (continued)**

TT. Peak Power Factor – The Power Factor at the time of the Customer's Maximum On-Peak Demand for the month.

UU. Power Factor – The ratio of real power to apparent power.

VV. Premise - The main residence, or living quarters for the use of a single family, or main building of a non-residential Customer, which includes the outlying or adjacent buildings used by the Customer provided the use of the service in the outlying or adjacent buildings is supplemental to the service used in the main residence or building.

WW. Present Value – The current value of a future payment, or stream of payments, discounted at the rate of return allowed by the IURC at the time the Company's Rate Schedules go into effect.

XX. Primary Line - Any distribution line of the Company operated at a nominal voltage greater than 600 volts and less than 69,000 volts.

YY. Qualifying Facility – A cogeneration or alternate energy production facility of eighty (80) MWs capacity or less which is owned not more than fifty percent (50%) in equity interest by a person primarily engaged in the generation or retail sale of electricity, gas, or thermal energy, as defined in the IURC Rules (170 IAC 4-4.1-1), or its successor.

ZZ. Rate Schedule - A part of the Tariff setting forth the availability and charges for service supplied to a particular group of Customers, as filed with and approved by the IURC.

AAA. Real-Time LMP – As defined in the Midwest ISO Open Access Transmission and Energy Markets Tariff ("TEMT") or its successor at the established NIPSCO Load Commercial Pricing Node(s).

BBB. Residential Service – Customers in whose name service is rendered exclusively for residential purposes, as defined by the IURC Rules (170 IAC 4-1-1), or its successor.

CCC. Rider - A part of the Tariff setting forth supplemental provisions applicable to specific Rate Schedules, as filed with and approved by the IURC.

DDD. Rules – A part of the Tariff setting forth the General Rules and Regulations Applicable to Electric Service, as filed with and approved by the IURC.

EEE. Secondary Line – Any distribution line of the Company operated at a nominal voltage of 600 volts or less.

FFF. Substation – The electric equipment, structures, land and land rights, including transformers, switches, protective devices and other apparatus necessary to transform Energy from a Transmission or Primary Line voltage.

GENERAL RULES AND REGULATIONS
Applicable to Electric Service

11. RENDERING AND PAYMENT OF BILLS

11.1 Payment of Bills

Bills will be issued monthly and must be paid by the due date specified on the Customer's Bill at an office or an established collection agency of the Company. Bills rendered on estimated readings for service in months in which meters are not read shall have the same force and effect as those based on actual meter readings.

11.2 Payment After Due Date of Service Bill

A bill is delinquent unless payment is received by the due date printed on the bill. The due date is seventeen (17) days from the next business day of the statement date printed on the bill. A delinquent bill may be assessed a late payment charge equal to ten percent (10%) of the first three dollars ($3) and three percent (3%) of the remaining amount that is delinquent and the Company may disconnect service after complying with any applicable IURC Rules.

Failure to receive the bill shall not entitle the Customer to relief from the deferred payment provisions of the rate if the Customer fails to make payment within said seventeen-day period, nor shall it affect the right of the Company to disconnect service for non-payment as above provided.

Once in each half calendar year, but not more often, the Company may upon the Customer's request waive the late payment charge on a delinquent bill, provided payment is tendered not later than the last date for payment of net amount of the next succeeding month's bill.

11.3 Social Security Payment Plan

The Company may, upon request, extend the due date by ten (10) calendar days, provided that the Customer applies for and is accepted by the Company as a participant in the Social Security Payment Plan. In order to participate in the Social Security Payment Plan, the Customer must meet the following conditions:

a. The Customer must be taking Residential service, which must be in the Customer's name; and

b. The Customer must be retired or be legally disabled and must show proof of receiving monthly social security benefits.

RATE 521
RATE FOR ELECTRIC SERVICE
GENERAL SERVICE SMALL

TO WHOM AVAILABLE

Available to non-residential General Service Customers for electric service who are located on the Company's Distribution Lines suitable and adequate for supplying the service requested, subject to the conditions set forth in this Rate Schedule and the Company Rules. Customers served by Transmission Lines shall not take service under this Rate Schedule.

Customers electing this Rate Schedule shall have a rolling twelve month average Energy consumption less than 5,000 kWh per month. If no historical information is available, the usage shall be estimated by the Company.

If the Company determines that the Customer is no longer eligible for the rate the Company will notify the Customer before moving them to a different Rate Schedule.

CHARACTER OF SERVICE

The Company will supply service from its electric supply lines at only such frequency, phase, regulation, and one standard secondary voltage or the available primary voltage as it has in the location where service is required. (See Company Rule 3 for the Company's standard voltages.)

If the Customer has 60 hertz electric generating equipment, other than minor standby equipment for emergency use, the Customer may parallel its 60 hertz system with the Company's 60 hertz supply. The Customer shall so regulate its use of electric Energy as not to cause excessive pulsations or fluctuations in the current or voltage in the Company's system or be subject to termination of service.

DETERMINATION OF AMOUNT OF ELECTRIC SERVICE SUPPLIED

The electric service to be supplied under this Rate shall be measured as to an Energy consumption by a Watt-Hour meter to be installed by the Company.

RATE

The rate for electric service and Energy supplied hereunder shall consist of a Customer Charge, an Energy Charge and applicable Riders. The Customer Charge, and Energy Charge are as follows:

Customer Charge

$12.55 per month

Energy Charge

$0.09283 per kilowatt hour for all kilowatt hours used per month

Demand Charge

$22.49 per kilowatt per month

Energy Charge

$0.00401 per kilowatt hour for all kilowatt hours used per month

DETERMINATION OF BILLING DEMAND

The Billing Demand for the current Month shall be the greatest of the following Demands:

1. Maximum Demand in On-Peak Hours for the past twelve (12) months up to and including the current Month.
2. 50% of the Maximum Demand in Off-Peak Hours for the past twenty four (24) months up to and including the current month.

DETERMINATION OF MAXIMUM DEMAND

Customer's Maximum Demand in any month shall be determined as defined in Company Rule 1.

ADJUSTMENTS

1. Adjustment for Metering at Different Voltage Level than the Voltage at Which Service Is Taken:

If, at the Company's option and in its sole discretion, the metering is installed at a voltage level that is greater than the voltage level at which service is taken, the kilowatt hours metered will be reduced by 1.2% before computing the Energy Charge, and the Maximum Demand in each period will be reduced by 1.2% before the Billing Demand is determined. If, at the Company's option and in its sole discretion, the metering is installed at a voltage level that is less than the voltage level at which service is taken, the kilowatt hours metered will be increased by 1.2% before computing the Energy Charge, and the Maximum Demand in each period will be increased by 1.2% before the Billing Demand is determined.

2. Deduction for Primary Service:

If service is taken by the Customer at a primary voltage (as defined in Company Rule 3) and if the Customer supplies and maintains all transformation equipment (primary voltage to utilization voltage), the monthly Demand Charge will be reduced by $2.90 per kilowatt of the monthly Billing Demand.

3. **Deduction for Transmission Service:**

If service is taken by the Customer at a transmission voltage as defined in Company Rule 3, and if the Customer supplies and maintains all transformation equipment (transmission voltage to utilization voltage), the monthly Demand Charge will be reduced by $8.73 per kilowatt of monthly Billing Demand.

MONTHLY MINIMUM CHARGE

The Customer's Monthly Minimum Charge under this rate shall be the sum of the Customer Charge and the Demand Charge.

GENERAL TERMS AND CONDITIONS OF SERVICE - CONTRACT

Any Customer requesting service under this rate shall enter into a written contract for an initial period of not less than three years.

In such contract it shall be proper to include such provisions, if any, as may be agreed upon between the Company and the Customer with respect to special terms and conditions under which service is to be furnished hereunder, including but not limited to, amount of Contract Demand, voltage to be supplied, and facilities to be provided by each party in accordance with the Company Rules.

RULES AND REGULATIONS

Service hereunder shall be subject to the Company Rules and IURC Rules.

RATE 533
RATE FOR ELECTRIC SERVICE
GENERAL SERVICE LARGE

TO WHOM AVAILABLE

Available to non-Residential Customers whose facilities are located adjacent to existing electric facilities having capacity sufficient to meet the Customer's requirements, subject to the conditions set forth in this Rate Schedule and the Company Rules.

Customers electing this Rate Schedule shall have a Maximum Demand of 300 kW or greater for at least two (2) of the past twelve (12) Months.

CHARACTER OF SERVICE

The Company will supply service to the extent of the capacity available from its electric supply lines, at such frequency, phase, regulation and one standard secondary voltage, or the available primary or transmission voltage at the location where service is required. (See Company Rule 3 for the Company's standard voltages.)

The Customer, at its own expense, shall furnish, supply, install and maintain, beginning at the point of delivery all necessary equipment for transmitting, protecting, switching, transforming, converting, regulating, and utilizing said electric Energy on the premises of the Customer.

The Customer will also supply in accordance with plans and specifications furnished by the Company and at a mutually agreed upon location on the Customer's property, suitable buildings, structures, and foundations to house and support the metering and any protecting, switching, relaying equipment that may be supplied by the Company.

If the Customer has 60 hertz electric generating equipment, other than minor standby equipment for emergency use, the Customer may parallel its 60 hertz system with the Company's 60 hertz supply. The Customer shall so regulate its use of electric Energy as not to cause excessive pulsations or fluctuations in the current or voltage in the Company's system or be subject to termination of service.

DETERMINATION OF AMOUNT OF ELECTRIC SERVICE SUPPLIED

The electric service to be supplied under this rate shall be measured as to Maximum Demand, Energy consumption and Reactive Kilovolt-Amperes by an IDR Meter to be installed by the Company.

RATE

The rate for electric service and Energy supplied hereunder shall consist of a Customer Charge, an Energy Charge, a Demand Charge and applicable Riders. The Customer Charge, Energy Charge, and Demand Charge are as follows:

Customer Charge

$580.00 per month

Demand Charge

$20.00 per kilowatt of Billing Demand per month

Energy Charge

$0.00448 per kilowatt hour for all kilowatt hours used per month

DETERMINATION OF BILLING DEMAND

For Customers with IDR Meters, the Billing Demand for the month shall be the greatest of the following Demands:

1. 90% of the Maximum Summer Peak Hour Demand for the past twenty-four (24) months up to and including the current month.
2. 80% of the Maximum Non-Summer Peak Hour Demand for the past twenty-four (24) months up to and including the current month.

For Customers with DI Meters, the Billing Demand for the month shall be the 85% of the Maximum Demand for the current month until such time as the Company installs an IDR meter.

DETERMINATION OF MAXIMUM DEMAND

Customer's Maximum Demand in any month shall be determined as defined in Company Rule 1.

ADJUSTMENTS

1. **Adjustment for Metering at Different Voltage Level than the Voltage at Which Service Is Taken:**

   If, at the Company's option and in its sole discretion, the metering is installed at a voltage level that is greater than the voltage level at which service is taken, the kilowatt hours metered will be reduced by 1.2% before computing the Energy Charge, and the Maximum Demand in each period will be reduced by 1.2% before the Billing Demand is determined. If, at the Company's option and in its sole discretion, the metering is installed at a voltage level that is less than the voltage level at which service is taken, the kilowatt hours metered will be increased by 1.2% before computing the Energy Charge, and the Maximum Demand in each period will be increased by 1.2% before the Billing Demand is determined.

RATE 541
RATE FOR ELECTRIC SERVICE
WATER PUMPING

TO WHOM AVAILABLE

1. Metered Service

Metered service is available to municipalities, the Indiana Department of Natural Resources and to corporations or persons operating under exclusive franchise to furnish water service at retail within a municipality for electric power service to be used for waterpumping purposes; who enter into a written contract for electric service in accordance with this Rate Schedule and who are located on the Company's electric supply lines suitable and adequate for supplying the service requested, subject to the conditions set forth in this Rate Schedule and the Company Rules.

Lighting Service will be supplied under this Rate Schedule only if it is incidental to the power load served and the lighting service in kilowatt Demand and kilowatt hour usage is less than 15 percent of the kilowatt hours respectively of the power load.

2. Un-metered Service

Un-metered service is available to private or governmental entities to provide power to systems for the pumping and removal of residential and small commercial sewage water and waste at multiple locations to a central waste water treatment facility. This rate is available only for an integrated system consisting of individual distributed pumping units which operate intermittently. No single pump may exceed 1.1 horsepower Energy rating or have a maximum Energy consumption exceeding 200 kilowatt hours per year. The distributed pumps comprising the wastewater pumping system must be located in the service territory of the Company on electric facilities suitable and adequate for supplying the service required.

Prior to installing new pumping devices, Customer must notify Company the time and date of the proposed installations so that Company may verify the number of pumps installed for billing purposes. Customer agrees to allow the Company to audit the records of the Waste Water Pumping System, two (2) times per year, to verify the number and size of the pumps located on the Company's lines. Company also reserves the right to install metering devices on one or more pumps from time to time, to verify the Demand and Energy consumption levels of installed pumps. Customer may not install pumps that do not meet the size restrictions of Company lines, Customer will remove, at its own costs and expense, any such pump.

CHARACTER OF SERVICE

The Company will supply service from its electric supply lines at only such frequency, phase, regulation, and voltage as it has available in the location where service is required, and if transformation of voltage is desired by the Customer, will transform its primary voltage to one standard secondary voltage. (See Company Rule 3 for the Company's standard voltages.)

Demand Charge

$15.60 per kilowatt of Maximum Demand per month

Energy Charge

$0.00479 per kilowatt hour for all kilowatt hours used per month

MONTHLY MINIMUM CHARGE

The Customer's Monthly Minimum Charge under this rate shall be the sum of the Customer Charge and Demand Charge.

DETERMINATION OF DEMAND

The Customer's Demand of electric Energy supplied shall be determined for each one-hour interval of the month. The phrase "one-hour interval" shall mean sixty (60) minute period beginning or ending on a numbered clock hour as indicated by the clock controlling the metering equipment.

DETERMINATION OF BILLING DEMAND

The Billing Demand for the month shall be the greatest of the following Demands:

1. The maximum one-hour Demand registered for the month.
2. Eighty percent (80%) of the highest Billing Demand established in the immediately preceding twenty three (23) months, adjusted, if the Company's obligation to serve is increased or decreased. Each time the Company's obligation to serve is increased or decreased, the highest Billing Demand established in the immediately preceding twenty three (23) months shall be adjusted by a ratio of the Company's current obligation to serve and the Company's obligation to serve in the month of the highest Billing Demand before multiplying by eighty percent (80%).

RULES AND REGULATIONS

Service hereunder shall be subject to the Company Rules and IURC Rules.

RIDER 570
ADJUSTMENT OF CHARGES FOR COST OF FUEL RIDER

TO WHOM AVAILABLE

This Rider shall be applicable to the Rate Schedules as defined in Appendix A.

RATE

A. Energy use under all Rate Schedules included in this rider are subject to charges for fuel cost and such charges shall be increased or decreased to the nearest 0.001 mill ($.000001) per KWH in accordance with the following:

$$\text{Adjustment Factor} = \frac{F}{S}$$

where:

1. "F" is the estimated expense of fuel based on a three-month average cost beginning with the month immediately following the twenty-day period allowed by the Commission in IC 8-1-2-42 (b) and consisting of the following costs:

   (a) the average cost of fossil fuel consumed in the Company's own plants, such cost being only those items listed in Account 151 of the Federal Energy Regulatory Commission's Uniform System of Accounts for Class A and B Public Utilities and Licensees; and

   (b) Other costs approved by the Commission for recovery.

2. "S" is the 3-month KWH sales forecast for each Rate Schedule.

B. The fuel cost charge as computed above shall be further modified to allow the recovery of gross receipts taxes and other similar revenue based tax charges occasioned by the fuel cost charge revenues.

C. The fuel cost charge shall be further modified to reflect the difference in the estimated incremental fuel cost billed and the incremental fuel cost actually experienced during the first and succeeding billing cycle month(s) or calendar months(s) in which such estimated incremental fuel cost was billed for those months not previously reconciled.

D. See Appendix B for fuel cost charge.

RIDER 571
RELIABILITY ADJUSTMENT

TO WHOM AVAILABLE

This Rider shall be applicable to the Rate Schedules as defined in Appendix A.

CHARGES FOR RELIABILITY ADJUSTMENT FACTOR

Energy Charges in the Rate Schedules included in this Tariff are subject to charges to reflect the recovery of non-FAC MISO costs and purchased power costs, including energy and capacity and the return of non-FAC MISO credits and sharing of off-system sale margins. Such charges shall be increased or decreased to the nearest 0.001 mill ($.000001) per KWH in accordance with the following:

Reliability Factor ("RF") = ((D x P) + (E x Pe)) / S

Where:

"RF" is the rate adjustment for each Rate Schedule.
"D" equals the total Demand related expenses including but not limited to capacity purchases.
"P" represents the Production Demand Allocation percentage for each Rate Schedule.
"E" equals the total Energy related expenses including but not limited to purchased power, off system sales margins and non-FAC MISO charges and credits.
"Pe" represents the Production Energy Allocation percentage for each Rate Schedule.
"S" is the 3-month KWH sales forecast for each Rate Schedule.

RELIABILITY ADJUSTMENT FACTOR

The above rates are subject to an Reliability Adjustment Factor set forth in accordance with the Order of the Commission approved [Date], in Cause No.43526. The Reliability Adjustment Factor stated in Appendix C is applicable hereto and is issued and effective at the dates shown on Appendix C.

The RA as computed above shall be further modified to allow the recovery of gross receipts taxes and other similar revenue based tax charges occasioned by the RA revenues and later reconciled with actual sales and revenues.

See Appendix C for RA's per KWH charge for each Rate Schedule.

RIDER 572
ENVIRONMENTAL COST RECOVERY MECHANISM

TO WHOM AVAILABLE

This Rider shall be applicable to the Rate Schedules as defined in Appendix A.

ADJUSTMENT OF CHARGES FOR ENVIRONMENTAL COST RECOVERY MECHANISM FACTOR

Energy Charges in the Rate Schedules included in this Tariff are subject to charges approved by the Commission to reflect rate base treatment for qualified pollution control property, and such charges shall be increased or decreased to the nearest 0.001 mill ($.000001) per KWH in accordance with the following:

Environmental Cost Recovery Mechanism Factor ("ECRM") = (RxP)/S

Where:

"ECRM" is the rate adjustment for each Rate Schedule representing the ratemaking treatment for qualified pollution control property.
"R" equals the total revenue requirement based upon the costs for the qualified pollution control property.
"P" represents the Production Demand Allocation percentage for the Rate Schedule.
"S" is the forecast 6-month KWH sales for the Rate Schedule.

ENVIRONMENTAL COST RECOVERY MECHANISM FACTOR

The above rates are subject to an Environmental Cost Recovery Mechanism Factor set forth in accordance with the Order of the Commission approved November 26, 2002, in Cause No. 42150. The Environmental Cost Recovery Mechanism Factor stated in Appendix D is applicable hereto and is issued and effective at the dates shown on Appendix D.

The ECRM as computed above shall be further modified to allow the recovery of gross receipts taxes and other similar revenue based tax charges occasioned by the ECRM revenues and later reconciled with actual sales and revenues.

See Appendix D for ECRM's per KWH charge for each Rate Schedule.

RIDER 573
ENVIRONMENTAL EXPENSE RECOVERY MECHANISM

TO WHOM AVAILABLE

This Rider shall be applicable to the Rate Schedules as defined in Appendix A.

ADJUSTMENT OF CHARGES FOR ENVIRONMENTAL EXPENSE RECOVERY MECHANISM FACTOR

Energy Charges in the Rate Schedules included in this Tariff are subject to charges to reflect the recovery of operation and maintenance and depreciation expenses for qualified pollution control property placed in service, and such charges shall be increased or decreased to the nearest 0.001 mill ($.000001) per KWH in accordance with the following:

Environmental Expense Recovery Mechanism Factor ("EERM") = ((D x P) + (O&M x Pc)) / S

Where:

"EERM"	is the rate adjustment for each Rate Schedule representing the recovery of operation and maintenance and depreciation expenses for qualified pollution control property placed in service.
"D"	equals the total six (6)-month depreciation expense for the qualified pollution control property placed in service.
"P"	represents the Production Demand Allocation percentage for each Rate Schedule.
"O&M"	equals the total six (6)-month operation and maintenance expense for the qualified pollution control property placed in service and net emission allowance purchases.
"Pc,"	a percentage value, equals a composite allocation based on: x(%) times P defined above for each Rate Schedule; and (1-x)(%) times "Te," where:
"Te"	represents the Energy Allocation Percentage for each Rate Schedule; and
"S"	is the forecast six (6)-month KWH sales for each Rate Schedule.

ENVIRONMENTAL EXPENSE RECOVERY MECHANISM FACTOR

The above rates are subject to an Environmental Expense Recovery Mechanism Factor set forth in accordance with the Order of the Commission approved November 26, 2002, in Cause No. 42150. The Environmental Expense Recovery Mechanism Factor stated in Appendix E is applicable hereto and is issued and effective at the dates shown on Appendix E.

The EERM as computed above shall be further modified to allow the recovery of gross receipts taxes and other similar revenue based tax charges occasioned by the EERM revenues and later reconciled with actual sales and revenues.

See Appendix E for EERM's per KWH charge for each Rate Schedule.

RIDER 574
ADJUSTMENT OF CHARGES FOR POWER FACTOR

TO WHOM AVAILABLE

This Rider shall be applicable to the Rate Schedules as defined in Appendix A.

A Customer requesting service for the applicable Rate Schedules shall be subject to an adjustment of charges for Power Factor based on the criteria listed in this Rider.

RATE

POWER FACTOR CALCULATION

Determination of Lagging Reactive Kilovolt Amperes

The Customer's requirements in Lagging Reactive Kilovolt Amperes shall be determined for each half-hour (1/2 hour) interval of the month and shall be two (2) times the number of Lagging Kilovolt Amperes recorded during such half-hour (1/2 hour) interval.

Determination of Lagging Power Factor

The Power Factor shall be calculated for each half-hour (1/2 hour) interval for the month from the kilowatt-hours "A", as obtained from the metering equipment, and the Lagging Reactive Kilovolt Ampere Hours "B", as defined above, which are used in the same half-hour (1/2 hour) interval, by the following formula:

$$PowerFactor = \frac{A}{\sqrt{A^2 + B^2}}$$

The Peak Power Factor (PPF) is defined as the Power Factor at the time of the Customer's Maximum On-Peak Demand for the month, as defined in Company Rule 1.

Adjustment for Power Factor

For Peak Power Factors of less than 95% lagging, an amount equal to:

$$\text{\$--}Voltage\ Factor \times [B - (A \times .32868)]$$

shall be added to the Customer's bill.

The $-Voltage Factors are as follows for delivery voltage of:

Transmission - $1.14 Distribution - $0.60

For Peak Power Factors equal to or in excess of 95% lagging, no adjustment shall be made to the Customer's bill.

GENERAL TERMS AND CONDITIONS FOR PURCHASE

1. **Contract**

   Any cogenerator or small power producer requesting service under this rate shall enter into a written contract for an initial period of not less than one year.

2. **Curtailment of Purchase**

   The Company reserves the right to Curtail the purchase at any time when necessary to make emergency repairs. For the purpose of making other than emergency repairs, the Company reserves the right to disconnect the Qualifying Facility's electric system for four (4) consecutive hours on any Sunday, or such other day or days as may be agreed to by the Qualifying Facility and the Company, provided forty-eight (48) hours' notification previous to the hour of cut-off is given the Qualifying Facility of such intention.

3. **Additional Load**

   The Qualifying Facility shall notify the Company in writing of any substantial additions to or alterations in the equipment supplying electric Energy to the Company and such additions or alterations shall not be connected to the system until such notice shall have been given by the Qualifying Facility and received by the Company.

4. **Discontinuance of Purchase**

   The Company shall have the right to cut off and discontinue the purchase of electric Energy and remove its metering equipment and other property when there is a violation by the Qualifying Facility of any of the terms or conditions of the contract.

5. **Back-up and Maintenance Power**

   Back-up and maintenance power is electrical Energy and capacity provided by the Company to a Qualified Facility to replace Energy, ordinarily generated by the Qualifying Facility, during a scheduled or unscheduled outage of the Qualifying Facility.

GENERAL TERMS AND CONDITIONS OF SERVICE - CONTRACT

Any Qualified Facility requesting service under this rate shall enter into a written contract for an initial period of not less than three years. The Qualified Facility has the right to have back-up service or scheduled maintenance outages not to exceed the hours selected to a combined maximum of 1,000 hours in each consecutive contract year period. Any additional Energy taken by the Qualified Facility will be billed under an appropriate Rate Schedule.

RIDER 578
INTERCONNECTION STANDARDS

TO WHOM AVAILABLE

This Rider shall be applicable to the Rate Schedules as defined in Appendix A.

In accordance with 170 IAC 4-4.3 of the Commission Rules, as the same may be revised from time to time by the Commission, applicable to Customer-generator Interconnection Standards, ("Rule 4.3") eligible Customers may own, operate, and interconnect generation equipment to the NIPSCO electric system after meeting the requirements of Rule 4.3, these rules and the approval process as defined.

DEFINITIONS

A Customer shall initiate the approval process by submitting the appropriate application (see Interconnection Agreements below) and fees based on the size and type of the generating unit as defined by the following:

Level 1: Inverter-based Customer-generator facilities with a name plate rating of 10kW or less which meet certification requirements of section 5 of Rule 4.3.

Level 2: Customer-based generator facilities with a name plate rating for 2 MW or less which meet the certification requirements of section 5 of Rule 4.3.

Level 3: Customer-based generator facilities which do not qualify for either Level 1 or Level 2.

RATE

The interconnection review fees shall be as follows:

Level 1: There is no charge.

Level 2: The charge for a Level 2 interconnection review is fifty dollars ($50) plus one dollar ($1) per kW of the Customer-generator facility's name plate capacity.

Level 3: The charge for a Level 3 review is one hundred dollars ($100) plus two dollars ($2) per kW of the Customer-generator facility's name plate capacity, as well as one hundred dollars ($100) per hour for engineering work performed as part of any impact or facilities study. The cost of additional facilities in order to accommodate the interconnection of the Customer-generator facility shall be the responsibility of the applicant.

RIDER 579
NET METERING

TO WHOM AVAILABLE

This Rider shall be applicable to the Rate Schedules as defined in Appendix A.

REQUIREMENTS

In accordance with 170 IAC 4-4.2 of the Commission Rules applicable to net metering, residential and K-12 school Customers may own and operate a solar, wind or hydro electrical generating facility ("Facility") and may be considered an eligible net metering Customer if the Customer is in good standing and the Facility:

1. has a total nameplate capacity less than or equal to ten (10) kilowatts (KW);
2. is located on the eligible net metering Customer's premises and operated by the Customer; and
3. is used primarily to offset all or part of the eligible net metering Customer's own electricity requirements

The Company may offer net metering to other Customers at the Company's discretion.

An eligible net metering Customer whose account is not more than thirty (30) days in arrears and who does not have any legal orders outstanding pertaining to any account with the Company is qualified as an eligible net metering Customer in good standing.

The aggregate amount of net metering capacity allowable to all eligible Customers under this rule shall be determined by the sum of each Facility's nameplate capacity and shall not exceed one tenth of one percent (0.1%) of the most recent summer peak retail load of the Company.

Before the Company will allow interconnection with an eligible net metering Customer's Facility and before net metering service may begin, the Customer will be required to enter into an interconnection agreement applicable to the Facility as set forth in Rider 578 – Interconnection Standards.

The eligible net metering Customer shall install, operate and maintain the Facility in accordance with the manufacturer's suggested practice for safe, efficient and reliable operation interconnected to the Company's electric system.

The Company will determine an eligible net metering Customer's monthly bill as follows:

1. Rates and adjustments will be in accordance with the Company's electric service Tariff and general rules that would apply if the eligible net metering Customer did not participate in net metering.

2. The Company will measure the difference between the amount of electricity delivered by the Company to the eligible net metering Customer and the amount of electricity generated by the eligible net metering Customer and delivered to the Company during the Month, in accordance with the Company's normal metering practices. If the kilowatt hours (kWh) delivered by the Company to the

eligible net metering Customer exceed the kWh delivered by the eligible net metering Customer to the Company during the Month, the eligible net metering Customer will be billed for the kWh difference at the rate applicable to the eligible net metering Customer if it was not an eligible net metering Customer. If the kWh generated by the eligible net metering Customer and delivered to the Company exceeds the kWh supplied by the Company to the eligible net metering Customer during the Month, the eligible net metering Customer shall be credited in the next billing cycle for the kWh difference.

3. When eligible net metering Customer elects to no longer participate in net metering under this Rule, any unused credit shall revert to the Company.

APPENDIX A
APPLICABLE RIDERS

Rider	Code	Rider Name	Applicable Tariffs
Rider 570	FAC	Adjustment of Charges for Cost of Fuel Rider	511, 521, 523, 526, 527, 533, 534, 536, 541, 544, 550, 555, 560
Rider 571	RA	Reliability Adjustment	511, 521, 523, 526, 527, 533, 534, 536, 541, 544, 550, 555, 560
Rider 572	ECRM	Adjustment of Charges for Environmental Cost Recovery Mechanism	511, 521, 523, 526, 527, 533, 534, 536, 541, 544, 550, 555, 560
Rider 573	EERM	Adjustment of Charges for Environmental Expense Recovery Mechanism	511, 521, 523, 526, 527, 533, 534, 536, 541, 544, 550, 555, 560
Rider 574	PF	Adjustment of Charges for Power Factor	526, 527, 533, 534, 536
Rider 575	ES	Electric Spaceheating Rider to Residential Service	511
Rider 576	TS	Thermal Storage Rider	523, 533
Rider 577	COG	Purchases from Cogeneration and Small Power Production Facilities	511, 521, 523, 526, 527, 533, 534, 536
Rider 578	IS	Interconnection Standards Rider	511, 521, 523, 526, 527, 533, 534, 536
Rider 579	NM	Net Metering Rider – Residential Service and K-12 Schools	511, 521, 523, 533
Rider 580	EDR	Economic Development Rider	523, 533, 534

APPENDIX B
FUEL COST CHARGE

The charges in Rates Schedules 511, 521, 523, 526, 527, 533, 534 536, 541, 544, 550, 555 and 560 are subject to the Fuel Cost Charge computed in accordance with Rider 570 – Adjustment of Charges for Cost of Fuel Rider.

Effective for all bills rendered during the [ ] billing months, the Fuel Cost Charge shall be:

A charge of [ ] per kilowatt hour

APPENDIX C
RELIABILITY ADJUSTMENT FACTOR

The Reliability Adjustment Factor in Rates 511, 521, 523, 526, 527, 533, 534, 536, 541, 544, 550, 555 and 560 shall be on the basis of a charge to reflect the rate base treatment of Qualified Pollution Control Property, set forth in Rider 571 and in accordance with the Order of the IURC approved [Date] in Cause No. 43526, as follows:

Effective for bills rendered beginning with Date billing, the Reliability Adjustment Factor shall be:

RATE SCHEDULES

Rate	Charge
Rate 511 A charge of $	per kwh used per month
Rate 521 A charge of $	per kwh used per month
Rate 523 A charge of $	per kwh used per month
Rate 526 A charge of $	per kwh used per month
Rate 527 A charge of $	per kwh used per month
Rate 533 A charge of $	per kwh used per month
Rate 534 A charge of $	per kwh used per month
Rate 536 A charge of $	per kwh used per month
Rate 541 A charge of $	per kwh used per month
Rate 544 A charge of $	per kwh used per month
Rate 550 A charge of $	per kwh used per month
Rate 555 A charge of $	per kwh used per month
Rate 560 A charge of $	per kwh used per month

APPENDIX D
ENVIRONMENTAL COST RECOVERY MECHANISM FACTOR

The Environmental Cost Recovery Mechanism Factor in Rates 511, 521, 523, 526, 527, 533, 534, 536, 541, 544, 550, 555 and 560 shall be on the basis of a charge to reflect the rate base treatment of qualified pollution control property, set forth in Rider 572 and in accordance with the Order of the IURC approved November 26, 2002, in Cause No. 42150, as follows:

Effective for bills rendered beginning with the [   ] 20XX billing, the Environmental Cost Recovery Mechanism Factor shall be:

RATE SCHEDULES

Rate	Charge
Rate 511 A charge of $	per kwh used per month
Rate 521 A charge of $	per kwh used per month
Rate 523 A charge of $	per kwh used per month
Rate 526 A charge of $	per kwh used per month
Rate 527 A charge of $	per kwh used per month
Rate 533 A charge of $	per kwh used per month
Rate 534 A charge of $	per kwh used per month
Rate 536 A charge of $	per kwh used per month
Rate 541 A charge of $	per kwh used per month
Rate 544 A charge of $	per kwh used per month
Rate 550 A charge of $	per kwh used per month
Rate 555 A charge of $	per kwh used per month
Rate 560 A charge of $	per kwh used per month

APPENDIX E
ENVIRONMENTAL EXPENSE RECOVERY MECHANISM FACTOR

The Environmental Expense Recovery Mechanism Factor in Rates 511, 521, 523, 526, 527, 533, 534, 536, 541, 544, 550, 555 and 560 shall be on the basis of a charge to reflect the rate base treatment of qualified pollution control property, set forth in Rider 573 in accordance with the Order of the IURC approved November 26, 2002, in Cause No. 42150, as follows:

Effective for bills rendered beginning with [ ] 2008 billing, the Environmental Expense Recovery Mechanism Factor shall be:

RATE SCHEDULES

Rate	Charge
Rate 511 A charge of $	per kwh used per month
Rate 521 A charge of $	per kwh used per month
Rate 523 A charge of $	per kwh used per month
Rate 526 A charge of $	per kwh used per month
Rate 527 A charge of $	per kwh used per month
Rate 533 A charge of $	per kwh used per month
Rate 534 A charge of $	per kwh used per month
Rate 536 A charge of $	per kwh used per month
Rate 541 A charge of $	per kwh used per month
Rate 544 A charge of $	per kwh used per month
Rate 550 A charge of $	per kwh used per month
Rate 555 A charge of $	per kwh used per month
Rate 560 A charge of $	per kwh used per month

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GENERAL RULES AND REGULATIONS
Applicable to Electric Service

1. DEFINITIONS (continued)

NN. National Electric Code – The standard for the safe installation of electrical wiring and equipment. It is part of the National Fire Codes series published by the National Fire Protection Association (NFPA).

OO. Non-Sufficient Funds – An account shall be considered to have Non-Sufficient Funds for the following reasons:

1. The Customer's payment is considered delinquent by the banking institution.
2. The Customer has supplied the incorrect bank account number.
3. The Customer's bank account number is no longer available.
4. The Customer has issued a stop payment by the banking institution to the Company.
5. The Customer pays electronically, and a chargeback is subsequently assessed by the Customer's financial institution.
6. Any other instance when the financial institution refuses to honor the tendered payment.

PP. Off-Peak Demand – The Demand taken during Off-Peak Hours.

QQ. Off-Peak Hours - All hours not defined as On-Peak Hours shall be considered Off-Peak hours.

RR. On-Peak Demand - The Demand taken during On-Peak Hours.

SS. On-Peak Hours – Defined as the hours listed below:

Winter classified as October 1 through March 31

On-Peak Hours are those commencing at 1:00 p.m. Central Standard Time (C.S.T.) and ending at 9:00 p.m., Central Standard Time (C.S.T.), Monday through Friday excluding the holidays set forth below.

Summer classified as April 1 through September 30

On-Peak Hours are those commencing at 11:00 a.m. Central Standard Time (C.S.T.) and ending at 7:00 p.m., Central Standard Time (C.S.T.), Monday through Friday excluding the holidays set forth below.

Holidays include New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day and Christmas Day and are considered to be Off-Peak Hours for the entire twenty-four hours. If the holidays listed above occur on a Saturday and the preceding Friday is a legally observed holiday, the entire twenty four hours of such Friday will be considered off-peak hours. If the holiday listed occurs on a Sunday and the following Monday is legally observed as a holiday, the entire twenty-four hours of such Monday will be considered as off-peak hours.

GENERAL RULES AND REGULATIONS
Applicable to Electric Service

1. DEFINITIONS (continued)

TT. Peak Power Factor – The Power Factor at the time of the Customer's Maximum On-Peak Demand for the month.

UU. Power Factor – The ratio of real power to apparent power.

VV. Premise - The main residence, or living quarters for the use of a single family, or main building of a non-residential Customer, which includes the outlying or adjacent buildings used by the Customer provided the use of the service in the outlying or adjacent buildings is supplemental to the service used in the main residence or building.

WW. Present Value – The current value of a future payment, or stream of payments, discounted at the rate of return allowed by the IURC at the time the Company's Rate Schedules go into effect.

XX. Primary Line - Any distribution line of the Company operated at a nominal voltage greater than ~~between~~ 600 volts and less than 69,000 ~~34,500~~ volts.

YY. Qualifying Facility – A cogeneration or alternate energy production facility of eighty (80) MWs capacity or less which is owned not more than fifty percent (50%) in equity interest by a person primarily engaged in the generation or retail sale of electricity, gas, or thermal energy, as defined in the IURC Rules (170 IAC 4-4.1-1), or its successor.

ZZ. Rate Schedule - A part of the Tariff setting forth the availability and charges for service supplied to a particular group of Customers, as filed with and approved by the IURC.

AAA. Real-Time LMP – As defined in the Midwest ISO Open Access Transmission and Energy Markets Tariff ("TEMT") or its successor at the established NIPSCO Load Commercial Pricing Node(s).

BBB. Residential Service – Customers in whose name service is rendered exclusively for residential purposes, as defined by the IURC Rules (170 IAC 4-1-1), or its successor.

CCC. Rider - A part of the Tariff setting forth supplemental provisions applicable to specific Rate Schedules, as filed with and approved by the IURC.

DDD. Rules – A part of the Tariff setting forth the General Rules and Regulations Applicable to Electric Service, as filed with and approved by the IURC.

EEE. Secondary Line – Any distribution line of the Company operated at a nominal voltage of 600 volts or less.

FFF. Substation – The electric equipment, structures, land and land rights, including transformers, switches, protective devices and other apparatus necessary to transform Energy from a Transmission or Primary Line voltage.

GENERAL RULES AND REGULATIONS
Applicable to Electric Service

11. RENDERING AND PAYMENT OF BILLS

11.1 Payment of Bills

Bills will be issued monthly and must be paid by the due date specified on the Customer's Bill at an office or an established collection agency of the Company. Bills rendered on estimated readings for service in months in which meters are not read shall have the same force and effect as those based on actual meter readings.

11.2 Payment After Due Date of Service Bill

A bill is delinquent unless payment is received by the due date printed on the bill. The due date is seventeen (17) days from the next business day of the statement date printed on the bill. A delinquent bill may be assessed a late payment charge equal to ten percent (10%) of the first three dollars ($3) and three percent (3%) of the remaining amount that is delinquent and the Company may disconnect service after complying with any applicable IURC Rules.

Failure to receive the bill shall not entitle the Customer to relief from the deferred payment provisions of the rate if the Customer fails to make payment within said seventeen-day period, nor shall it affect the right of the Company to disconnect service for non-payment as above provided.

Once in each half calendar year, but not more often, the Company may upon the Customer's request waive the late payment charge on a delinquent bill, provided payment is tendered not later than the last date for payment of net amount of the next succeeding month's bill.

11.3 Social Security Payment Plan

The Company may, upon request, extend the due date by ten (10) calendar days, provided that the Customer applies for and is accepted by the Company as a participant in the Social Security Payment Plan. In order to participate in the Social Security Payment Plan, the Customer must meet the following conditions:

a. The Customer must be taking Residential service, which must be in the Customer's name; and

b. The Customer must be retired or be legally disabled and must show proof of receiving monthly social security benefits.~~; and~~

~~The Customer's normal due date falls either on or between the first and the fourth day, or on or between the twenty-first and last day of the month.~~

RATE 521
RATE FOR ELECTRIC SERVICE
GENERAL SERVICE SMALL

TO WHOM AVAILABLE

Available to non-residential General Sservice Customers for electric service who are located on the Company's Distribution Lines suitable and adequate for supplying the service requested, subject to the conditions set forth in this Rate Schedule and the Company Rules. Customers served by Transmission Lines shall not take service under this Rate Schedule.

Customers electing this Rate Schedule shall have a rolling twelve month average Energy consumption less than 5,000 kWh per month. If no historical information is available, the usage shall be estimated by the Company.

If the Company determines that the Customer is no longer eligible for the rate the Company will notify the Customer before moving them to a different Rate Schedule.

CHARACTER OF SERVICE

The Company will supply service from its electric supply lines at only such frequency, phase, regulation, and one standard secondary voltage or the available primary voltage as it has in the location where service is required. (See Company Rule 3 for the Company's standard voltages.)

If the Customer has 60 hertz electric generating equipment, other than minor standby equipment for emergency use, the Customer may parallel its 60 hertz system with the Company's 60 hertz supply. The Customer shall so regulate its use of electric Energy as not to cause excessive pulsations or fluctuations in the current or voltage in the Company's system or be subject to termination of service.

DETERMINATION OF AMOUNT OF ELECTRIC SERVICE SUPPLIED

The electric service to be supplied under this Rate shall be measured as to an Energy consumption by a Watt-Hour meter to be installed by the Company.

RATE

The rate for electric service and Energy supplied hereunder shall consist of a Customer Charge, an Energy Charge and applicable Riders. The Customer Charge, and Energy Charge are as follows:

Customer Charge

$12.55 per month

Energy Charge

$0.09283 per kilowatt hour for all kilowatt hours used per month

Demand Charge

$22.49 per kilowatt per month

Energy Charge

$0.00401 per kilowatt hour for all kilowatt hours used per month

DETERMINATION OF BILLING DEMAND

The Billing Demand for the current Month shall be the greatest of the following Demands:

1. Maximum Demand in On-Peak Hours for the past twelve (12) months up to and including the current Month.
2. 50% of the Maximum Demand in Off-Peak Hours for the past twenty four (24) months up to and including the current month.

DETERMINATION OF MAXIMUM DEMAND

Customer's Maximum Demand in any month shall be determined as defined in Company Rule 1.

ADJUSTMENTS

~~3.~~1. Adjustment for Metering at Different Voltage Level than the Voltage at Which Service Is Taken:

If, at the Company's option and in its sole discretion, the metering is installed at a voltage level that is greater than the voltage level at which service is taken, the kilowatt hours metered will be reduced by 1.2% before computing the Energy Charge, and the Maximum Demand in each period will be reduced by 1.2% before the Billing Demand is determined. If, at the Company's option and in its sole discretion, the metering is installed at a voltage level that is less than the voltage level at which service is taken, the kilowatt hours metered will be increased by 1.2% before computing the Energy Charge, and the Maximum Demand in each period will be increased by 1.2% before the Billing Demand is determined.

~~4.~~2. Deduction for Primary Service:

If service is taken by the Customer at a primary voltage (as defined in Company Rule 3) and if the Customer supplies and maintains all transformation equipment (primary voltage to utilization voltage), the monthly Demand Charge will be reduced by $2.90 per kilowatt of the monthly Billing Demand.

~~5.~~3. **Deduction for Transmission Service:**

If service is taken by the Customer at a transmission voltage as defined in Company Rule 3, and if the Customer supplies and maintains all transformation equipment (transmission voltage to utilization voltage), the monthly Demand Charge will be reduced by $8.73 per kilowatt of monthly Billing Demand.

MONTHLY MINIMUM CHARGE

The Customer's Monthly Minimum Charge under this rate shall be the sum of the Customer Charge and the Demand Charge.

GENERAL TERMS AND CONDITIONS OF SERVICE - CONTRACT

Any Customer requesting service under this rate shall enter into a written contract for an initial period of not less than three years.

In such contract it shall be proper to include such provisions, if any, as may be agreed upon between the Company and the Customer with respect to special terms and conditions under which service is to be furnished hereunder, including but not limited to, amount of Contract Demand, voltage to be supplied, and facilities to be provided by each party in accordance with the Company Rules.

RULES AND REGULATIONS

Service hereunder shall be subject to the Company Rules and IURC Rules.

RATE 533
RATE FOR ELECTRIC SERVICE
GENERAL SERVICE LARGE

TO WHOM AVAILABLE

Available to non-Residential Customers whose facilities are located adjacent to existing electric facilities having capacity sufficient to meet the Customer's requirements, subject to the conditions set forth in this Rate Schedule and the Company Rules.

Customers electing this Rate Schedule shall have a Maximum Demand of 300 kW or greater for at least two (2) of the past twelve (12) Months.

CHARACTER OF SERVICE

The Company will supply service to the extent of the capacity available from its electric supply lines, at such frequency, phase, regulation and one standard secondary voltage, or the available primary or transmission voltage at the location where service is required. (See Company Rule 3 for the Company's standard voltages.)

The Customer, at its own expense, shall furnish, supply, install and maintain, beginning at the point of delivery all necessary equipment for transmitting, protecting, switching, transforming, converting, regulating, and utilizing said electric Energy on the premises of the Customer.

The Customer will also supply in accordance with plans and specifications furnished by the Company and at a mutually agreed upon location on the Customer's property, suitable buildings, structures, and foundations to house and support the metering and any protecting, switching, relaying equipment that may be supplied by the Company.

If the Customer has 60 hertz electric generating equipment, other than minor standby equipment for emergency use, the Customer may parallel its 60 hertz system with the Company's 60 hertz supply. The Customer shall so regulate its use of electric Energy as not to cause excessive pulsations or fluctuations in the current or voltage in the Company's system or be subject to termination of service.

DETERMINATION OF AMOUNT OF ELECTRIC SERVICE SUPPLIED

The electric service to be supplied under this rate shall be measured as to Maximum Demand, Energy consumption and Reactive Kilovolt-Amperes by an IDR Meter to be installed by the Company.

RATE

The rate for electric service and Energy supplied hereunder shall consist of a Customer Charge, an Energy Charge, a Demand Charge and applicable Riders. The Customer Charge, Energy Charge, and Demand Charge are as follows:

Customer Charge

$580.00 per month

Demand Charge

$20.00 per kilowatt of Billing Demand per month

Energy Charge

$0.00448 per kilowatt hour for all kilowatt hours used per month

DETERMINATION OF BILLING DEMAND

For Customers with IDR Meters, the Billing Demand for the month shall be the greatest of the following Demands:

1. 90% of the Maximum Summer Peak Hour Demand for the past twenty-four (24) months up to and including the current month.
2. 80% of the Maximum Non-Summer Peak Hour Demand for the past twenty-four (24) months up to and including the current month.

For Customers with DI Meters, the Billing Demand for the month shall be the 85% of the Maximum Demand for the current month until such time as the Company installs an IDR meter.

DETERMINATION OF MAXIMUM DEMAND

Customer's Maximum Demand in any month shall be determined as defined in Company Rule 1.

ADJUSTMENTS

1. **Adjustment for Metering at Different Voltage Level than the Voltage at Which Service Is Taken:**

   If, at the Company's option and in its sole discretion, the metering is installed at a voltage level that is greater than the voltage level at which service is taken, the kilowatt hours metered will be reduced by 1.2% before computing the Energy Charge, and the Maximum Demand in each period will be reduced by 1.2% before the Billing Demand is determined. If, at the Company's option and in its sole discretion, the metering is installed at a voltage level that is less than the voltage level at which service is taken, the kilowatt hours metered will be increased by 1.2% before computing the Energy Charge, and the Maximum Demand in each period will be increased by 1.2% before the Billing Demand is determined.

RATE 541
RATE FOR ELECTRIC SERVICE
WATER PUMPING

TO WHOM AVAILABLE

1. **Metered Service**

Metered service is available to municipalities, the Indiana Department of Natural Resources and to corporations or persons operating under exclusive franchise to furnish water service at retail within a municipality for ~~such~~ electric power service to be used for waterpumping purposes; who enter into a written contract for electric service in accordance with this Rate Schedule and who are located on the Company's electric supply lines suitable and adequate for supplying the service requested, subject to the conditions set forth in this Rate Schedule and the Company Rules.

Lighting Service will be supplied under this Rate Schedule only if it is incidental to the power load served and the lighting service in kilowatt Demand and kilowatt hour usage is less than 15 percent of the kilowatt hours respectively of the power load.

2. **Un-metered Service**

Un-metered service is available to private or governmental entities to provide power to systems for the pumping and removal of residential and small commercial sewage water and waste at multiple locations to a central waste water treatment facility. This rate is available only for an integrated system consisting of individual distributed pumping units which operate intermittently. No single pump may exceed 1.1 horsepower Energy rating or have a maximum Energy consumption exceeding 200 kilowatt hours per year. The distributed pumps comprising the wastewater pumping system must be located in the service territory of the Company on electric facilities suitable and adequate for supplying the service required.

Prior to installing new pumping devices, Customer must notify Company the time and date of the proposed installations so that Company may verify the number of pumps installed for billing purposes. Customer agrees to allow the Company to audit the records of the Waste Water Pumping System, two (2) times per year, to verify the number and size of the pumps located on the Company's lines. Company also reserves the right to install metering devices on one or more pumps from time to time, to verify the Demand and Energy consumption levels of installed pumps. Customer may not install pumps that do not meet the size restrictions of Company lines, Customer will remove, at its own costs and expense, any such pump.

CHARACTER OF SERVICE

The Company will supply service from its electric supply lines at only such frequency, phase, regulation, and voltage as it has available in the location where service is required, and if transformation of voltage is desired by the Customer, will transform its primary voltage to one standard secondary voltage. (See Company Rule 3 for the Company's standard voltages.)

Demand Charge

$15.60 per kilowatt of Maximum Demand per month

Energy Charge

$0.00479 per kilowatt hour for all kilowatt hours used per month

MONTHLY MINIMUM CHARGE

The Customer's Monthly Minimum Charge under this rate shall be the sum of the Customer Charge and~~,~~ Demand Charge ~~and the Energy Charge~~.

DETERMINATION OF DEMAND

The Customer's Demand of electric Energy supplied shall be determined for each one-hour interval of the month. The phrase "one-hour interval" shall mean sixty (60) minute period beginning or ending on a numbered clock hour as indicated by the clock controlling the metering equipment.

DETERMINATION OF BILLING DEMAND

The Billing Demand for the month shall be the greatest of the following Demands:

1. The maximum one-hour Demand registered for the month.
2. Eighty percent (80%) of the highest Billing Demand established in the immediately preceding twenty three (23) months, adjusted, if the Company's obligation to serve is increased or decreased. Each time the Company's obligation to serve is increased or decreased, the highest Billing Demand established in the immediately preceding twenty three (23) months shall be adjusted by a ratio of the Company's current obligation to serve and the Company's obligation to serve in the month of the highest Billing Demand before multiplying by eighty percent (80%).

RULES AND REGULATIONS

Service hereunder shall be subject to the Company Rules and IURC Rules.

RIDER 570
ADJUSTMENT OF CHARGES FOR COST OF FUEL RIDER

TO WHOM AVAILABLE

This Rider shall be applicable to the Rate Schedules as defined in Appendix A.

RATE

A. Energy use under all Rate Schedules included in this rider are subject to charges for fuel cost and such charges shall be increased or decreased to the nearest 0.001 mill ($.000001) per KWH in accordance with the following:

$$\text{Adjustment Factor} = \frac{F}{S}$$

where:

1. "F" is the estimated expense of fuel based on a three-month average cost beginning with the month immediately following the twenty-day period allowed by the Commission in IC 8-1-2-42 (b) and consisting of the following costs:

   (a) the average cost of fossil fuel consumed in the Company's own plants, such cost being only those items listed in Account 151 of the Federal Energy Regulatory Commission's Uniform System of Accounts for Class A and B Public Utilities and Licensees; and

   (b) Other costs approved by the Commission for recovery.

2. "S" is the 3-month KWH sales forecast for each Rate Schedule.~~estimated kilowatt-hour sales for the same estimated period set forth in "F", consisting of the net sum in kilowatt-hours of:~~

   ~~(a)net generation; and~~

   ~~(b) Energy losses and Company use~~

B. The fuel cost charge as computed above shall be further modified to allow the recovery of gross receipts taxes and other similar revenue based tax charges occasioned by the fuel cost charge revenues.

C. The fuel cost charge shall be further modified to reflect the difference in the estimated incremental fuel cost billed and the incremental fuel cost actually experienced during the first and succeeding billing cycle month(s) or calendar months(s) in which such estimated incremental fuel cost was billed for those months not previously reconciled.

D. See Appendix B for fuel cost charge.

Issued Date
Date

Effective Date
Date

A NiSource Company

RIDER 571
RELIABILITY ADJUSTMENT

TO WHOM AVAILABLE

This Rider shall be applicable to the Rate Schedules as defined in Appendix A.

CHARGES FOR RELIABILITY ADJUSTMENT FACTOR

Energy Charges in the Rate Schedules included in this Tariff are subject to charges to reflect the recovery of non-FAC MISO costs and purchased power costs, including energy and capacity and the return of non-FAC MISO credits and sharing of off-system sale margins. Such charges shall be increased or decreased to the nearest 0.001 mill ($.000001) per KWH in accordance with the following:

Reliability Factor ("RF") = ((D x P) + (E x Pe)) / S

Where:

"RF" is the rate adjustment for each Rate Schedule.
"D" equals the total Demand related expenses including but not limited to capacity purchases.
"P" represents the Production Demand Allocation percentage for each Rate Schedule.
"E" equals the total Energy related expenses including but not limited to purchased power, off system sales margins and non-FAC MISO charges and credits.
"Pe" represents the Production Energy Allocation percentage for each Rate Schedule.
"S" is the ~~forecast~~ 3-month KWH sales forecast for each Rate Schedule.

RELIABILITY ADJUSTMENT FACTOR

The above rates are subject to an Reliability Adjustment Factor set forth in accordance with the Order of the Commission approved [Date], in Cause No.43526. The Reliability Adjustment Factor stated in Appendix C is applicable hereto and is issued and effective at the dates shown on Appendix C.

The RA as computed above shall be further modified to allow the recovery of gross receipts taxes and other similar revenue based tax charges occasioned by the RA revenues and later reconciled with actual sales and revenues.

See Appendix C for RA's per KWH charge for each Rate Schedule.

RIDER 572
ENVIRONMENTAL COST RECOVERY MECHANISM

TO WHOM AVAILABLE

This Rider shall be applicable to the Rate Schedules as defined in Appendix A.

ADJUSTMENT OF CHARGES FOR ENVIRONMENTAL COST RECOVERY MECHANISM FACTOR

Energy Charges in the Rate Schedules included in this Tariff are subject to charges approved by the Commission to reflect rate base treatment for qualified pollution control property, and such charges shall be increased or decreased to the nearest 0.001 mill ($.000001) per KWH in accordance with the following:

~~**ENVIRONMENTAL COST RECOVERY MECHANISM FACTOR**~~

~~The above rates are subject to an Environmental Cost Recovery Mechanism Factor set forth in accordance with the Order of the Commission approved November 26, 2002, in Cause No. 42150. The Environmental Cost Recovery Mechanism Factor stated in Appendix D is applicable hereto and is issued and effective at the dates shown on Appendix D.~~

Environmental Cost Recovery Mechanism Factor ("ECRM") = (RxP)/S

Where:

"ECRM" is the rate adjustment for each Rate Schedule representing the ratemaking treatment for qualified pollution control property.
"R" equals the total revenue requirement based upon the costs for the qualified pollution control property.
"P" represents the Production Demand Allocation percentage for the Rate Schedule.
"S" is the forecast 6-month KWH sales for the Rate Schedule.

ENVIRONMENTAL COST RECOVERY MECHANISM FACTOR

The above rates are subject to an Environmental Cost Recovery Mechanism Factor set forth in accordance with the Order of the Commission approved November 26, 2002, in Cause No. 42150. The Environmental Cost Recovery Mechanism Factor stated in Appendix D is applicable hereto and is issued and effective at the dates shown on Appendix D.

The ECRM as computed above shall be further modified to allow the recovery of gross receipts taxes and other similar revenue based tax charges occasioned by the ECRM revenues and later reconciled with actual sales and revenues.

See Appendix D for ECRM's per KWH charge for each Rate Schedule.

RIDER 573
ENVIRONMENTAL EXPENSE RECOVERY MECHANISM

TO WHOM AVAILABLE

This Rider shall be applicable to the Rate Schedules as defined in Appendix A.

ADJUSTMENT OF CHARGES FOR ENVIRONMENTAL EXPENSE RECOVERY MECHANISM FACTOR

Energy Charges in the Rate Schedules included in this Tariff are subject to charges to reflect the recovery of operation and maintenance and depreciation expenses for qualified pollution control property placed in service, and such charges shall be increased or decreased to the nearest 0.001 mill ($.000001) per KWH in accordance with the following:

Environmental Expense Recovery Mechanism Factor ("EERM") = ((D x P) + (O&M x Pc)) / S

Where:

"EERM"	is the rate adjustment for each Rate Schedule representing the recovery of operation and maintenance and depreciation expenses for qualified pollution control property placed in service.
"D"	equals the total six (6)-month depreciation expense for the qualified pollution control property placed in service.
"P"	~~-~~represents the Production Demand Allocation percentage for each Rate Schedule.
"O&M"	equals the total six (6)-month operation and maintenance expense for the qualified pollution control property placed in service and net emission allowance purchases.
"Pc,"	a percentage value, equals a composite allocation based on: x(%) times P defined ~~in (c)~~ above for each Rate Schedule; and (1-x)(%) times "Te," where:
"Te"	represents the Energy Allocation Percentage for each Rate Schedule; and
"S"	is the forecast six (6)-month KWH sales for each Rate Schedule.

ENVIRONMENTAL EXPENSE RECOVERY MECHANISM FACTOR

The above rates are subject to an Environmental Expense Recovery Mechanism Factor set forth in accordance with the Order of the Commission approved November 26, 2002, in Cause No. 42150. The Environmental Expense Recovery Mechanism Factor stated in Appendix E is applicable hereto and is issued and effective at the dates shown on Appendix E.

The EERM as computed above shall be further modified to allow the recovery of gross receipts taxes and other similar revenue based tax charges occasioned by the EERM revenues and later reconciled with actual sales and revenues.

See Appendix E for EERM's per KWH charge for each Rate Schedule.

RIDER 574
ADJUSTMENT OF CHARGES FOR POWER FACTOR

TO WHOM AVAILABLE

This Rider shall be applicable to the Rate Schedules as defined in Appendix A.

A Customer requesting service for the applicable Rate Schedules shall be subject to an adjustment of charges for Power Factor based on the criteria listed in this Rider.

RATE

POWER FACTOR CALCULATION

Determination of Lagging Reactive Kilovolt Amperes

The Customer's requirements in Lagging Reactive Kilovolt Amperes shall be determined for each half-hour (1/2 hour) interval of the month and shall be two (2) times the number of Lagging Kilovolt Amperes recorded during such half-hour (1/2 hour) interval.

Determination of Lagging Power Factor

The Power Factor shall be calculated for each half-hour (1/2 hour) interval for the month from the kilowatt-hours "A", as obtained from the metering equipment, and the Lagging Reactive Kilovolt Ampere Hours "B", as defined above, which are used in the same half-hour (1/2 hour) interval, by the following formula:

$$PowerFactor = \frac{A}{\sqrt{A^2 + B^2}}$$

The Peak Power Factor (PPF) is defined as the Power Factor at the time of the Customer's Maximum On-Peak Demand for the month, as defined in Company Rule 1.

Adjustment for Power Factor

For Peak Power Factors of less than 95% lagging, an amount equal to:

$$\$\text{–}Voltage\ Factor \times [B - (A \times .32868)]$$

shall be added to the Customer's bill.

The \$-Voltage Factors are as follows for delivery voltage of:

Transmission - \$1.14 Distribution - \$0.60

For Peak Power Factors equal to or in excess of 95% lagging, no adjustment shall be made to the Customer's bill.

GENERAL TERMS AND CONDITIONS FOR PURCHASE

1. **Contract**

Any cogenerator or small power producer requesting service under this rate shall enter into a written contract for an initial period of not less than one year.

2. **Curtailment of Purchase**

The Company reserves the right to Curtail -the purchase at any time when necessary to make emergency repairs. For the purpose of making other than emergency repairs, the Company reserves the right to disconnect the Qualifying Facility's electric system for four (4) consecutive hours on any Sunday, or such other day or days as may be agreed to by the Qualifying Facility and the Company, provided forty-eight (48) hours' notification previous to the hour of cut-off is given the Qualifying Facility of such intention.

3. **Additional Load**

The Qualifying Facility shall notify the Company in writing of any substantial additions to or alterations in the equipment supplying electric Energy to the Company and such additions or alterations shall not be connected to the system until such notice shall have been given by the Qualifying Facility and received by the Company.

4. **Discontinuance of Purchase**

The Company shall have the right to cut off and discontinue the purchase of electric Energy and remove its metering equipment and other property when there is a violation by the Qualifying Facility of any of the terms or conditions of the contract.

5. **Back-up and Maintenance Power**

Back-up and maintenance power is electrical Energy and capacity provided by the Company to a Qualified Facility to replace Energy, ordinarily generated by the Qualifying Facility, during a scheduled or unscheduled outage of the Qualifying Facility.

GENERAL TERMS AND CONDITIONS OF SERVICE - CONTRACT

Any Qualified Facility requesting service under this rate shall enter into a written contract for an initial period of not less than three years. The Qualified Facility has the right to have back-up service or scheduled maintenance outages not to exceed the hours selected to a combined maximum of 1,000 hours in each consecutive contract year period. Any additional Energy taken by the Qualified Facility will be billed under an appropriate Rate Schedule.

RIDER 578
INTERCONNECTION STANDARDS

TO WHOM AVAILABLE

This Rider shall be applicable to the Rate Schedules as defined in Appendix A.

In accordance with 170 IAC 4-4.3 of the Commission Rules, as the same may be revised from time to time by the Commission, applicable to Customer-generator Interconnection Standards, ("Rule 4.3") eligible Customers may own, operate, and interconnect generation equipment to the NIPSCO electric system after meeting the requirements of Rule 4.3, these rules and the approval process as~~is~~ defined.

DEFINITIONS

A Customer shall initiate the approval process by submitting the appropriate application (see Interconnection Agreements below) and fees based on the size and type of the generating unit as defined by the following:

Level 1: Inverter-based Customer-generator facilities with a name plate rating of 10kW or less which meet certification requirements of section 5 of Rule 4.3.

Level 2: Customer-based generator facilities with a name plate rating for 2 MW or less which meet the certification requirements of section 5 of Rule 4.3.

Level 3: Customer-based generator facilities which do not qualify for either Level 1 or Level 2.

RATE

The interconnection review fees shall be as follows:

Level 1: There is no charge.

Level 2: The charge for a Level 2 interconnection review is fifty dollars ($50) plus one dollar ($1) per kW of the Customer-generator facility's name plate capacity.

Level 3: The charge for a Level 3 review is one hundred dollars ($100) plus two dollars ($2) per kW of the Customer-generator facility's name plate capacity, as well as one hundred dollars ($100) per hour for engineering work performed as part of any impact or facilities study. The cost of additional facilities in order to accommodate the interconnection of the Customer-generator facility shall be the responsibility of the applicant.

RIDER 579
NET METERING

TO WHOM AVAILABLE

This Rider shall be applicable to the Rate Schedules as defined in Appendix A.

REQUIREMENTS

In accordance with 170 IAC 4-4.2 of the Commission Rules applicable to net metering, residential and K-12 school Customers may own and operate a solar, wind or hydro electrical generating facility ("Facility") and may be considered an eligible net metering Customer if the Customer is in good standing and the Facility:

1. has a total nameplate capacity less than or equal to ten (10) kilowatts (KW);
2. is located on the eligible net metering Customer's premises and operated by the Customer; and
3. is used primarily to offset all or part of the eligible net metering Customer's own electricity requirements

The Company may offer net metering to other Customers at the Company's discretion.

An eligible net metering Customer whose account is not more than thirty (30) days in arrears and who does not have any legal orders outstanding pertaining to any account with the Company is qualified as an eligible net metering Customer in good standing.

The aggregate amount of net metering capacity allowable to all eligible Customers under this rule shall be determined by the sum of each Facility's nameplate capacity and shall not exceed one tenth of one percent (0.1%) of the most recent summer peak retail load of the Company.

Before the Company will allow interconnection with an eligible net metering Customer's Facility and before net metering service may begin, the Customer will be required to enter into an interconnection agreement applicable to the Facility as set forth in Rider 578~~7~~ – Interconnection Standards.

The eligible net metering Customer shall install, operate and maintain the Facility in accordance with the manufacturer's suggested practice for safe, efficient and reliable operation interconnected to the Company's electric system.

The Company will determine an eligible net metering Customer's monthly bill as follows:

1. Rates and adjustments will be in accordance with the Company's electric service Tariff and general rules that would apply if the eligible net metering Customer did not participate in net metering.

2. The Company will measure the difference between the amount of electricity delivered by the Company to the eligible net metering Customer and the amount of electricity generated by the eligible net metering Customer and delivered to the Company during the Month, in accordance with the Company's normal metering practices. If the kilowatt hours (kWh) delivered by the Company to the

eligible net metering Customer exceed the kWh delivered by the eligible net metering Customer to the Company during the Month, the eligible net metering Customer will be billed for the kWh difference at the rate applicable to the eligible net metering Customer if it was not an eligible net metering Customer. If the kWh generated by the eligible net metering Customer and delivered to the Company exceeds the kWh supplied by the Company to the eligible net metering Customer during the Month, the eligible net metering Customer shall be credited in the next billing cycle for the kWh difference.

3. When eligible net metering Customer elects to no longer participate in net metering under this Rule, any unused credit shall revert to the Company.

~~Before the Company may allow interconnection with an eligible Customer's facility, the Customer shall be required to enter into an interconnection agreement with the Company applicable to the facility. See Rider 577 – Interconnection Standards for the appropriate agreement.~~

APPENDIX A
APPLICABLE RIDERS

Rider	Code	Rider Name	Applicable Tariffs
Rider 570	FAC	Adjustment of Charges for Cost of Fuel Rider	511, 521, 523, 526, 527, 533, 534, 536, 541, 544, 550, 555, 560
Rider 571	RA	Reliability Adjustment	511, 521, 523, 526, 527, 533, 534, 536, 541, 544, 550, 555, 560
Rider 572	ECRM	Adjustment of Charges for Environmental Cost Recovery Mechanism	511, 521, 523, 526, 527, 533, 534, 536, 541, 544, 550, 555, 560
Rider 573	EERM	Adjustment of Charges for Environmental Expense Recovery Mechanism	511, 521, 523, 526, 527, 533, 534, 536, 541, 544, 550, 555, 560
Rider 574	PF	Adjustment of Charges for Power Factor	526, 527, 533, 534, 536
Rider 575	ES	Electric Spaceheating Rider to Residential Service	511
Rider 576	TS	Thermal Storage Rider	~~521,~~ 523, 533
Rider 577	COG	Purchases from Cogeneration and Small Power Production Facilities	511, 521, 523, 526, 527, 533, 534, 536
Rider 578	IS	Interconnection Standards Rider	511, 521, 523, 526, 527, 533, 534, 536~~, 541, 544, 550, 555, 560~~
Rider 579	NM	Net Metering Rider – Residential Service and K-12 Schools	511, 521, 523, 533
Rider 580	EDR	Economic Development Rider	523, 533, 534

APPENDIX B
FUEL COST CHARGE

The charges in Rates Schedules 511, 521, 523, 526, 527, 533, 534 536, 541, 544, 550, 555 and 560 are subject to the Fuel Cost Charge computed in accordance with Rider 570 – Adjustment of Charges for Cost of Fuel Rider.

Effective for all bills rendered during the [ ] billing months, the Fuel Cost Charge shall be:

A charge of [______] ~~$0.004693~~ per kilowatt hour

Issued Date
Date

Effective Date
Date

APPENDIX C
RELIABILITY ADJUSTMENT FACTOR

The Reliability Adjustment Factor in Rates 511, 521, 523, ~~524,~~ 526, 527, 533, 534, 536, 541, 544, 550, 555 and 560 shall be on the basis of a charge to reflect the rate base treatment of Qualified Pollution Control Property, set forth in Rider 571 and in accordance with the Order of the IURC approved [Date] in Cause No. 43526, as follows:

Effective for bills rendered beginning with Date billing, the Reliability Adjustment Factor shall be:

RATE SCHEDULES

Rate	Charge	
Rate 511	A charge of $	per kwh used per month
Rate 521	A charge of $	per kwh used per month
Rate 523	A charge of $	per kwh used per month
Rate 526	A charge of $	per kwh used per month
Rate 527	A charge of $	per kwh used per month
Rate 533	A charge of $	per kwh used per month
Rate 534	A charge of $	per kwh used per month
Rate 536	A charge of $	per kwh used per month
Rate 541	A charge of $	per kwh used per month
Rate 544	A charge of $	per kwh used per month
Rate 550	A charge of $	per kwh used per month
Rate 555	A charge of $	per kwh used per month
Rate 560	A charge of $	per kwh used per month

APPENDIX D
ENVIRONMENTAL COST RECOVERY MECHANISM FACTOR

The Environmental Cost Recovery Mechanism Factor in Rates 511, 521, 523, ~~524,~~ 526, 527, 533, 534, 536, 541, 544, 550, 555 and 560 shall be on the basis of a charge to reflect the rate base treatment of qualified pollution control property, set forth in Rider 572 and in accordance with the Order of the IURC approved November 26, 2002, in Cause No. 42150, as follows:

Effective for bills rendered beginning with the [ ] 20XX billing, the Environmental Cost Recovery Mechanism Factor shall be:

RATE SCHEDULES

Rate	Charge	
Rate 511	A charge of $	per kwh used per month
Rate 521	A charge of $	per kwh used per month
Rate 523	A charge of $	per kwh used per month
Rate 526	A charge of $	per kwh used per month
Rate 527	A charge of $	per kwh used per month
Rate 533	A charge of $	per kwh used per month
Rate 534	A charge of $	per kwh used per month
Rate 536	A charge of $	per kwh used per month
Rate 541	A charge of $	per kwh used per month
Rate 544	A charge of $	per kwh used per month
Rate 550	A charge of $	per kwh used per month
Rate 555	A charge of $	per kwh used per month
Rate 560	A charge of $	per kwh used per month

NORTHERN INDIANA PUBLIC SERVICE COMPANY
IURC Electric Service Tariff
Original Volume No. 11

CORRECTED
September 24, 2008
Original No. 115

APPENDIX E
ENVIRONMENTAL EXPENSE RECOVERY MECHANISM FACTOR

The Environmental Expense Recovery Mechanism Factor in Rates 511, 521, 523, 526, 527, 533, 534, 536, 541, 544, 550, 555 and 560 shall be on the basis of a charge to reflect the rate base treatment of qualified pollution control property, set forth in Rider 573 in accordance with the Order of the IURC approved November 26, 2002, in Cause No. 42150, as follows:

Effective for bills rendered beginning with [ ] 2008 billing, the Environmental Expense Recovery Mechanism Factor shall be:

RATE SCHEDULES

Rate	Charge	
Rate 511	A charge of $	per kwh used per month
Rate 521	A charge of $	per kwh used per month
Rate 523	A charge of $	per kwh used per month
Rate 526	A charge of $	per kwh used per month
Rate 527	A charge of $	per kwh used per month
Rate 533	A charge of $	per kwh used per month
Rate 534	A charge of $	per kwh used per month
Rate 536	A charge of $	per kwh used per month
Rate 541	A charge of $	per kwh used per month
Rate 544	A charge of $	per kwh used per month
Rate 550	A charge of $	per kwh used per month
Rate 555	A charge of $	per kwh used per month
Rate 560	A charge of $	per kwh used per month

NDS01 CEARLS 1065562~~3702~~v1

Issued Date
Date

Effective Date
Date

A NiSource Company